02 ANNUAL REPORT

SUNCOR ENERGY

FIRST IN OIL SANDS. 3,400 EXPERIENCED EMPLOYEES. 13 BILLION BARRELS OF **resources**. PLANS TO GROW **production** TO 1/2 MILLION BARRELS PER DAY. ACCESS TO THE LARGEST **market** IN THE WORLD. PROVEN GROWTH STRATEGY. COMMITTED TO SUSTAINABILITY AND GENERATING SHAREHOLDER VALUE.

count on it

count on it

Suncor Energy Inc. is an integrated energy company, strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In the 36 years since we made history tapping the oil sands to produce the first commercial barrel of synthetic crude oil, Suncor has expanded its assets and expertise with new resource leases, new technologies and a new vision for sustainable growth. Our vision – to more than double oil sands production to over half a million barrels per day in the next decade while also investing in emerging markets for renewable energy for the future.

Suncor's **resources**, **production** and **market** access add up to a proven growth strategy and a solid foundation for building shareholder value.

This Annual Report contains forward-looking statements that involve risks and uncertainties. Actual results may differ materially. See page 38 for additional information. All financial information is reported in Canadian dollars unless noted otherwise. Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint venture investments, unless the context otherwise requires.

SUNCOR'S ABILITY TO GENERATE SHAREHOLDER VALUE IS A REFLECTION OF THE COMPANY'S GROWING OIL PRODUCTION, EARNINGS AND CASH FLOW

Production
(thousands of barrels of oil equivalent per day)

	98	99	00	01	02
Natural Gas	57.5	[illegible]	40.5	[illegible]	33.7
[illegible]	93.6	105.6	113.9	123.2	205.8
Total	151.1	156.7	[illegible]	[illegible]	239.5

Net Earnings
(Cdn$ millions)

Cash Flow from Operations/ Net Debt
(Cdn$ millions)

	98	99	00	01	02
Cash Flow from Operations	580	[illegible]	958	[illegible]	1 440
[illegible]	1 280	[illegible]	[illegible]	3 143	2 671

Share Price
($ per share as of December 31)

SUNCOR'S ABILITY TO GENERATE SHAREHOLDER VALUE IS A REFLECTION OF THE COMPANY'S GROWING OIL PRODUCTION, EARNINGS AND CASH FLOW.

Production
(thousands of barrels of oil equivalent per day)

	98	99	00	01	02
Natural Gas	57.5	51.1	40.5	33.4	**33.7**
Oil Sands	93.6	105.6	113.9	123.2	**205.8**
Total	151.1	156.7	154.4	156.6	**239.5**

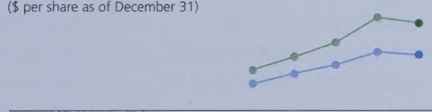
Net Earnings
(Cdn$ millions)

98	99	00	01	02
178	186	377	388	**761**

Cash Flow from Operations/ Net Debt
(Cdn$ millions)

	98	99	00	01	02
Cash Flow from Operations	580	591	958	831	**1 440**
Net Debt	1 289	1 334	2 236	3 143	**2 671**

Share Price
($ per share as of December 31)



	98	99	00	01	02
Share Price TSX (Cdn$)	11.50	15.10	19.15	26.20	**24.70**
Share Price NYSE (US$)	7.48	10.45	12.85	16.45	**15.67**

Suncor knows that long-term growth is not sustainable by financial performance alone. As we invest for future growth, Suncor is also investing in communities to build healthy, vibrant places to live and work and in new technologies to reduce our environmental footprint.

count on it

OIL SANDS

Fort McMurray, Alberta

Suncor's Oil Sands business extracts bitumen from the oil sands ore and upgrades it into diesel fuel and refinery-ready feedstock. In 2002, newly expanded facilities contributed to record production averaging 205,800 barrels per day. Construction is under way for the next phase of oil sands growth, which is designed to deliver production capacity of 260,000 barrels per day in 2005, growing in stages to a goal of 500,000 to 550,000 barrels per day by 2010 to 2012.

NATURAL GAS AND RENEWABLE ENERGY

Calgary, Alberta

The Natural Gas and Renewable Energy business (NG) supports Suncor's growth and financial goals by producing natural gas as a price hedge against consumption by Suncor's oil sands and refining operations. In 2002, NG produced 179 million cubic feet of natural gas per day, well in excess of internal demands of about 110 million cubic feet per day. At the same time, the business supports Suncor's environmental goals with low-emission hydrocarbon production, zero-emission renewable energy projects and a mandate to develop ways to manage and sequester carbon dioxide, a greenhouse gas.

ENERGY MARKETING AND REFINING

Toronto and Sarnia, Ontario

The Energy Marketing and Refining business (EM&R) is responsible for managing a portfolio of market channels with the objective of providing high returns and long-term stability on the sale of Suncor's products. As part of this strategy, EM&R markets Suncor's refinery feedstock, diesel fuel and natural gas production. EM&R also markets products from Suncor's Sarnia refinery to industrial and commercial consumers, primarily in Ontario and Quebec, and to retail customers through Sunoco-branded and joint venture service networks in Ontario. Gasoline sales volumes in the Sunoco-branded retail network grew by more than 4% in 2002.

SUNCOR'S VISION OF SUSTAINABILITY

A reduced environmental footprint, a positive social impact and strong financial performance contributing to a growing economy – Suncor's vision of sustainability is applied across all our businesses. As part of that vision, Suncor is investing in wind energy, a clean, renewable source of electricity.

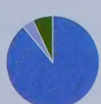
Suncor Energy's integrated operations produce and market a range of refinery feedstock and refined petroleum products for the North American market. To reduce commodity price risk and capture more value from oil sands production, the company explores for and produces natural gas as a price hedge against internal energy demand while working to develop stable, long-term markets for its products.

financial highlights

Year ended December 31 (Cdn$ millions)	**2002**	2001	2000	1999	1998
Financial					
Revenues	**4 904**	4 199	3 388	2 387	2 070
Net earnings	**761**	388	377	186	178
Cash flow provided from operations	**1 440**	831	958	591	580
Capital and exploration expenditures	**877**	1 678	1 998	1 350	936
Total assets	**8 683**	8 094	6 833	5 176	4 104
Net debt	**2 671**	3 143	2 236	1 334	1 289
Dollars per Common Share					
Net earnings	**1.64**	0.79	0.78	0.39	0.41
Cash flow provided from operations	**3.11**	1.76	2.06	1.26	1.32
Cash dividends	**0.17**	0.17	0.17	0.17	0.17
Key Ratios – %					
Debt to debt plus shareholders' equity	**43.7**	53.1	47.7	38.9	46.7
Net debt to cash flow from operations (times)	**1.9**	3.8	2.3	2.3	2.2
Return on shareholders' equity	**24.4**	14.8	16.5	10.3	12.3
Return on capital employed (1)	**14.6**	17.8	16.6	8.3	9.5
Oil Sands (1)	**16.8**	20.1	22.8	12.9	16.3
Natural Gas	**9.2**	32.1	17.2	5.5	3.3
Energy Marketing and Refining	**12.5**	18.4	20.5	6.0	7.4

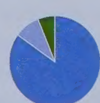
(1) Excludes major project costs until new assets are brought into operation.

Net Earnings
(per cent)



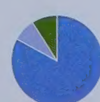
- Oil Sands **89**
- Natural Gas **4**
- Energy Marketing and Refining **7**

Cash Flow Provided from Operations
(per cent)



- Oil Sands **85**
- Natural Gas **9**
- Energy Marketing and Refining **6**

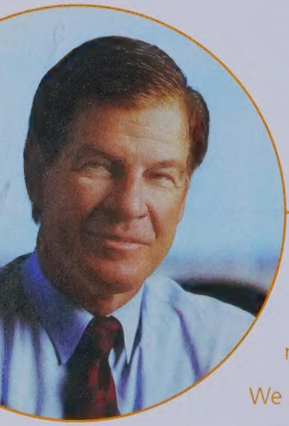
Capital Employed
(per cent)



- Oil Sands **83**
- Natural Gas **8**
- Energy Marketing and Refining **9**

MESSAGE TO SHAREHOLDERS February 2003

Rick George President and Chief Executive Officer



count on Suncor Energy

For the past decade, Suncor has implemented a business strategy that strives to mitigate risks, while maximizing the rewards of operating in a commodity industry. We believe the best way to create shareholder value is to take a long-term view of our business and focus on factors that we have the ability to control.

That deliberate, long-term vision paid off once again for Suncor in 2002, as we realized the rewards of a $3.4 billion investment in infrastructure, technology and people that nearly doubled our oil sands production capacity. In any industry, this is clearly a major investment. But in the energy industry in 1998 and 1999 – when oil prices and capital spending had plunged to historic lows – it took an unusual confidence for Suncor to confirm its commitment to an oil sands mega project. With the support of our shareholders and Board of Directors, Suncor forged ahead because we believed we could count on our growth strategy to deliver shareholder value over the long term.

Suncor's growth strategy is built on the strengths of the company's resource base, production assets, market access, and a dedicated and experienced team of employees. With nearly 13 billion barrels of resources and minimal finding costs, we have long believed that our Athabasca oil sands leases have world-class development potential. Building on those resources, our manufacturing approach to oil production leverages substantial assets and 36 years of experience in oil sands technology. And through our natural gas and energy marketing and refining operations, Suncor reduces the impact of natural gas price volatility and helps optimize returns by developing stable markets in Canada and the United States. In 2002, our work to build these three key elements – resources, production and markets – resulted in record production and sales that more than doubled our earnings per share and took Suncor's cash flow from operations over the billion dollar mark for the first time.

In addition to the rewards of expanded production, Suncor also benefited in 2002 from the continuing good faith of our shareholders and employees, as well as the regulators and communities that are so important to our future growth. Open and honest communication with stakeholders helps earn their continuing support for our growth plans as we move forward.

Suncor realized these results, in part, because of our deeply held belief that we must strive to be a company that can be counted on – counted on to continue our focused growth strategy, respond to community and environmental responsibilities and maintain our unwavering commitment to building shareholder value.

Suncor Share Performance
(Cdn$)

	92	93	94	95	96	97	98	99	00	01	**02**
● Suncor Share Price (TSX)	100	144	155	213	289	509	484	644	825	1 137	**1 079**
● TSX Integrated Oils Index	100	124	137	164	213	317	253	329	485	579	**630**
● S&P 500	100	110	114	153	189	251	323	391	356	314	**244**

This chart shows the total cumulative return, assuming the reinvestment of dividends, of $100 invested on December 31, 1992, in Suncor common shares.

As we turn our attention to the next stages of growth, Suncor will continue to follow the same strategy that has helped generate total average shareholder returns of more than 25% per year for the last decade. While Suncor's share price declined slightly along with the downward momentum in capital markets in 2002, the company outperformed the S&P 500 index. More important than the results of any single year, this is a company that is focused on long-term value creation and I believe we are well-positioned to realize future growth.

2002 Highlights

On the strength of our expanded oil sands operation, Suncor's company-wide average production increased to 239,500 barrels of oil equivalent per day from 156,600 barrels per day in 2001. Oil sands production increased 67% to an average 205,800 barrels per day in 2002. At $13.20 per barrel (excluding project start-up costs), cash operating costs were higher than anticipated on an annual basis. However, as our operations move to full production rates and we continue our efforts in cost reductions, we expect lower costs, particularly in the second half of 2003.

Building on the momentum of increasing oil sands production and plans to reduce costs, Suncor continued to put into place the steel and pipe for the company's next planned stages of growth. I am pleased to report that our first commercial-scale in-situ oil sands recovery project and associated upgrader expansion is on budget and on schedule. When complete, the first phase of the Firebag In-situ Oil Sands Project and expanded upgrader are expected to bring Suncor's production capacity to 260,000 barrels per day in 2005, an important step in reaching our goal of up to 550,000 barrels per day in 2010 to 2012.

On the financial side, increased production and strong oil prices drove record results. Net earnings nearly doubled to $761 million from $388 million in 2001, as did cash flow from operations, which reached a record $1.44 billion for the year, helping Suncor to quickly reduce debt levels.

The progress we made in 2002 puts in place a solid physical and financial foundation for our growth plans and plays an important role in our ongoing vision of doubling shareholder value every five years. There is no doubt this is an aggressive vision that will require clear strategic priorities and flawless execution.

Plans and Priorities

Suncor has four strategic priorities for 2003. We will focus on plans to reduce per barrel cash operating costs, increase production from our existing oil sands assets, further reduce our debt and continue to build the foundation for the next stages of our growth strategy. As we work on these key priorities, Suncor will continue to strive to be a global leader in safe and sustainable operations.

1 Reducing oil sands operating costs remains the overriding strategic priority for Suncor in 2003. We expect economies of scale with additional production will also be helped by initiatives resulting from a comprehensive review of oil sands operations. Suncor's goal is to reduce our

2002 MILESTONES

- Increased oil sands production 67% to an average of 205,800 barrels per day.
- Produced 179 million cubic feet of natural gas, well in excess of internal consumption.
- Delivered record net earnings of $761 million, record cash flow from operations of $1.44 billion and reduced net debt by more than $450 million.
- Initiated stakeholder consultation for the Voyageur growth strategy with a target of increasing production to more than half a million barrels of crude oil per day.
- Increased retail sales volumes in Suncor's Sunoco-branded retail network.
- Launched "Journey to Zero," a company-wide program aimed at eliminating workplace injuries.
- Advanced Suncor's climate change action plan through improved management systems and investment in research.

annual average cash operating costs to $12.50 per barrel this year, with a fourth quarter target as low as $10 to $11 per barrel. This is an aggressive target that assumes the price we pay for natural gas will average about US$3.60 per thousand cubic feet. High natural gas prices will pose a significant challenge to reaching our year-end cost reduction goal. However, because Suncor produces more natural gas than we consume, high prices will have a corresponding positive impact on the company's bottom line.

2 In 2003, Suncor plans to increase average daily production to a total of 250,000 barrels of oil equivalent per day, including 215,000 barrels per day of oil sands production. Average production levels for the year at our oil sands operation are expected to be lower than design capacity due to a planned one-month maintenance shutdown of Upgrader #1, our original upgrader. The maintenance shutdown, combined with the commissioning of a new fractionator, is expected to improve throughput and contribute to more reliable production.

3 We plan to continue directing part of our cash flow to reduce the company's net debt from year-end 2002 levels of about $2.7 billion. Our target is to maintain debt at two times cash flow from operations at a WTI price of US$20.

4 As we look beyond 2003, the company's growth plans will stay high on the agenda with construction continuing on the Firebag In-situ Oil Sands Project. This project will use in-situ technology to recover the large reserves on Suncor's Firebag leases. And because in-situ is expected to recover bitumen with less surface disturbance, our Firebag Project has the added benefit of reducing our environmental footprint.

The first stage of Firebag forms the cornerstone of our plan to boost oil sands production to 260,000 barrels per day in 2005. Three additional Firebag stages are currently planned for construction over the next several years, providing new bitumen supply to feed planned expansions of oil sands upgrading capacity.

We believe this staged approach, with engineering, procurement and construction managed internally, will keep our expansion plans on budget and on schedule.

The Firebag Project is the first critical step as we plan for Suncor's long-term Voyageur growth strategy. With Voyageur, Suncor is targeting production of 500,000 to 550,000 barrels of crude oil per day by 2010 to 2012. To reach that target, we are planning to construct a new coker unit that will increase upgrading capacity at our oil sands facility. The bitumen feed for the expanded upgrading operations is anticipated to come from in-situ development. The last piece of the Voyageur growth strategy calls for a third complete upgrading train, planned to be operational in 2010 to 2012. Each component of the Voyageur growth strategy – the new coker, additional in-situ phases and a new upgrader – will require approval from government regulators and Suncor's Board of Directors.

GOALS FOR 2003

- Increase oil sands production to an average of 215,000 barrels per day.
- Increase natural gas production volumes to 185 to 190 million cubic feet per day.
- Improve oil sands operational reliability through a maintenance shutdown of one of two upgraders.
- Reduce oil sands total cash operating costs to an annual average of $12.50 per barrel, exiting 2003 with costs as low as $10 to $11 per barrel, at an assumed natural gas price of US$3.60 per mcf.
- Begin steam injection at the Firebag In-situ Oil Sands Project with first bitumen in early 2004.
- Submit to regulators a development application to advance the Voyageur growth strategy.
- Roll out retail site redevelopment strategy for the Sunoco-brand retail network and begin producing low-sulphur gasoline ahead of regulated deadlines.
- Continue to pursue energy efficiencies, greenhouse gas offsets and new renewable energy projects.

To progress our growth plans, Suncor announced capital spending of just over $1 billion for 2003. While the majority of spending is budgeted for oil sands, we are planning investments across all of Suncor's businesses to support our growth strategy. Investments in Suncor's natural gas business will help production keep pace with internal demand, which is projected to increase with new in-situ development. In the downstream, new investment is planned to meet pending fuel desulphurization requirements and to lay the groundwork for refining Suncor's growing oil sands production volumes in the future.

Building on our parallel path strategy of meeting today's hydrocarbon energy needs while developing new energy sources for the future, Suncor has committed to investing $100 million in renewable energy by 2005. As we advance that commitment, we are targeting to launch plans for new wind power generation in 2003.

Overlying all of Suncor's strategic priorities is the safety of employees and contractors. In 2002, Suncor launched a program called "Journey to Zero" with a vision of eliminating lost-time injuries on company work sites. A company-wide management strategy, educational initiative and awards program supports Suncor's vision to be the safest company in Canada.

Sustainable Growth

Investments in wind power and a commitment to occupational safety are both part of Suncor's overall vision of sustainability – a vision that recognizes that a strong economy, a healthy environment and community well-being are complementary and interdependent. Suncor believes its integrated performance on these measures is a solid foundation for our future growth and profitability, helping us deliver strategies that are broad in scope and long-term in vision.

That long-term focus of sustainable development was the driving force behind Suncor's early actions to address our greenhouse gas emissions, starting nearly 10 years ago. Since then, we've made progress through various initiatives including energy-efficiency projects, carbon capture research and emissions trading, and we look forward to making further progress as Canada develops its plans to reduce greenhouse gas emissions. Based on reductions of 15% from 2010 business-as-usual energy intensity and the Government of Canada's stated plan to cap the price for carbon credits at $15 per tonne, Suncor estimates that in 2010 the impact of the Kyoto Protocol on cash operating costs would be about $0.20 to $0.27 per barrel. We believe this cost of compliance, while significant, will not have a material impact on Suncor. However, we recognize there are uncertainties and much work still to be done. The competitive position of Suncor, the oil sands industry and Canada all depend on a thoughtful and well-structured implementation plan up to, and beyond, the first Kyoto implementation period of 2008 to 2012. Suncor will continue to consult with governments and key stakeholders on this important issue.

"We must strive to be a company that can be counted on – counted on to continue our focused growth strategy, respond to community and environmental responsibilities and maintain our unwavering commitment to building shareholder value." **Rick George** President and Chief Executive Officer

Corporate Governance

While Suncor's past efforts helped us realize record results in 2002, it was a difficult year for the broader market as North American investor confidence waned following several well-publicized corporate failures and criticisms of corporate accounting practices. Counting on Suncor means having confidence in our commitment to good governance and providing current and potential investors with high quality disclosure. Suncor has been recognized repeatedly for the quality of our annual financial reporting, including best-in-industry awards from the Canadian Institute of Chartered Accountants for the past two years.

Count on Us

Suncor's Board of Directors guide the company's progress toward our goals in a manner consistent with long-term shareholder interests, good governance and our high standards of corporate conduct.

I am grateful to the Board for their counsel and the broad-based wealth of experience they provide to management.

Suncor's management team also benefits from the addition of Steve Williams, who joined us as executive vice president of corporate development and chief financial officer in May 2002. Steve's 20 years of industry experience in operations, strategic planning and environment, health and safety management is a natural fit with Suncor as we set out to become a world-class sustainable energy company.

While the Board of Directors and management team steward the interest of our shareholders at the strategic level, it is our employees who deliver that value-building strategy. The dedication, innovation and hard work of Suncor's employees are part of every success our company has realized in the past and every plan we have for the future. We strive to make Suncor a great place to work and I am honoured that our company is the employer of choice for so many promising young people as well as many of the industry's most experienced veterans.

Suncor is proud to be a business that people can count on, whether they're investors looking for a company with a proven strategy and great assets, community stakeholders who want to ensure their interests are heard, or employees looking for a place to grow and accomplish.

On behalf of the Board of Directors and all of our employees, I thank you for your confidence in Suncor. We'll do our best to build on the successes of the past as we continue our efforts to build shareholder value in the next decade and beyond. Count on it.

Rick George

Rick George
President and Chief Executive Officer

Suncor's integrated business strategy is built on developing the huge resources of the Athabasca oil sands. It uses internal natural gas production as a price hedge against energy use and cost-effective manufacturing technologies to upgrade the oil sands ore to marketable products. And it moves those products to markets through a variety of long-term contracts and Suncor-controlled retail channels, providing additional stability to sometimes volatile commodity markets.

count on Suncor's strategy

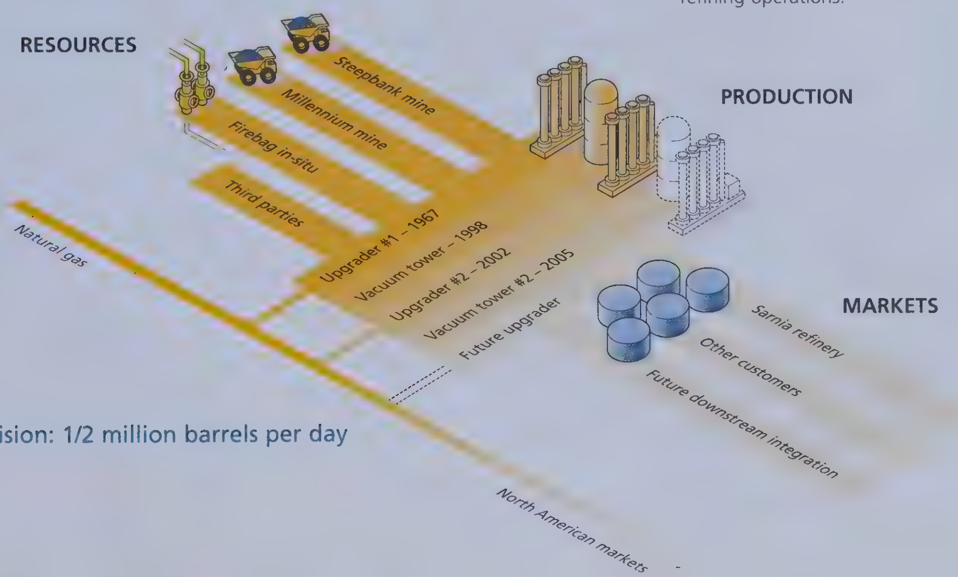
Since 1992, Suncor has increased its oil sands resource base with the addition of new mining leases and advanced plans to recover in-situ resources. We've more than tripled our oil sands production through improvements to our original upgrader and the addition of a second complete upgrading train in 2001. And we've increased our market access by securing stable long-term contracts with third party refiners and industrial and commercial customers.

How do we build on this proven formula to get to our goal of more than 500,000 barrels per day? Simple: make it bigger.

Over the next decade, we expect to add new **resource** supply as we build new stages of in-situ recovery and investigate accelerated recovery on our oil sands mining leases. At the same time, our goal is to increase natural gas production to maintain Suncor's price hedge against internal demand.

At the technological heart of our operations, oil sands **production** is expected to grow as Suncor progresses plans to add upgrading capacity with the addition of a second vacuum unit in 2005, a new set of cokers and ultimately a third complete upgrader.

In the downstream, Suncor will continue to strive to secure a balance of stable, long-term contracts in high value **markets** while investigating opportunities to expand the company's refining operations.



Vision: 1/2 million barrels per day

resources

13 billion barrels

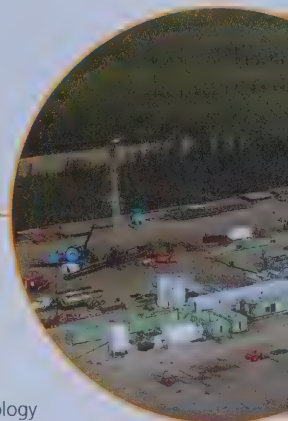
Suncor's operations and growth plans are focused on developing the Athabasca oil sands, one of the largest petroleum resource basins in the world. With nearly 13 billion barrels of resources, Suncor's leases have world-class development potential. Unlike conventional oil companies, Suncor does not have the risk and cost of the exploration phase of development. We know where the resources are. So while the need to replace declining production is driving conventional producers to drill deeper and in more remote locations, Suncor can focus on developing the technology and expertise to further our goal of being one of the lowest cost producers in North America.

A Big Back Yard

Suncor's mining and in-situ leases cover nearly 1,830 square kilometres. Because our in-situ leases are relatively close to the company's oil sands upgrading and production facilities, the company can use much of its existing plant infrastructure. Suncor also benefits from its relative close proximity to the city of Fort McMurray, Alberta, home of many of our oil sands employees.

3,400 EMPLOYEES – ONE VISION

Developing the company's resources goes beyond realizing the potential of Suncor's oil sands and natural gas reserves. It also means developing our human resources. Suncor strives to create a workplace that is safe, challenging, stimulating and fair; a place where each of the company's 3,400 employees has the opportunity to grow and accomplish. Our success depends on creating a workplace where commitment is freely given and employees have a strong desire to outperform the competition.



Four Key Benefits of In-situ

Since we began mining oil sands in 1967, Suncor has improved the efficiency of our operations with new technologies and processes such as the conversion to truck and shovel mining in the early 1990s. While mining remains at the centre of Suncor's recovery operations, in 2004 we will introduce the next phase in the evolution of oil sands recovery. The Firebag In-situ Oil Sands Project will use horizontal wells to reach the oil sands ore, heat it and bring the bitumen to the surface for processing. Each of the four stages of Firebag is expected to supply 35,000 barrels per day of bitumen for upgrading. Suncor is counting on four key benefits of in-situ as we advance our growth plans.

1 *Resource Access*

In-situ technology opens up the potential to recover large reserves that can't be reached economically by traditional mining methods.

2 *Staged Growth*

In-situ technology has the distinct advantage of being well-suited to development in small increments. Growing in smaller stages makes costs and budgets more predictable and allows a degree of flexibility to respond to labour and commodity markets.

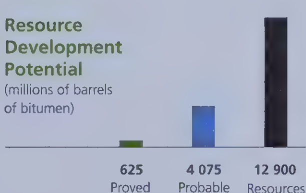
3 *Smaller Environmental Footprint*

Suncor's in-situ plans will use recycled water in a closed system for steam generation. No additional surface or ground water will be required and no tailings ponds will be created. In-situ is expected to disturb only about 10% of the surface land.

4 *Cost Reduction Potential*

In-situ technology is a proven but relatively new technology. As Suncor gains additional experience with operating an in-situ plant and as we continue to invest in research and development, we believe there will be significant potential to reduce the costs of recovery.

Resource Development Potential
(millions of barrels of bitumen)



Resources on Suncor leases, including proved and probable reserves, are estimated to be nearly 13 billion barrels. See Reserve Reconciliation on page 21.

production

the goal: 1/2 million barrels per day

Suncor doesn't find new production, we manufacture it. We are literally building on 36 years of oil sands development, with new technology and new investment. Expansion and improvements to our existing upgrading facilities are designed to provide more than just increased production of diesel and refinery feedstock – they are expected to provide greater operational flexibility through multiple upgrading trains and economies of scale that will reduce our operating costs per barrel.

Count Down for Costs

Suncor has a solid track record of delivering increased production and reducing operating costs. Economies of scale and improved technologies contributed to per barrel cash operating costs averaging $13.20 in 2002. Going into 2003, cost reductions remain a high priority for Suncor.

To advance that objective, we've launched a process of continuous, comprehensive review and improvement of our oil sands operations. We expect to see measurable results in the second half of 2003 as cost-cutting initiatives kick in and Suncor completes the planned maintenance shutdown of Upgrader #1. Based on average natural gas prices of US$3.60 per thousand cubic feet, Suncor's target is to reduce average oil sands cash operating costs to $12.50 per barrel in 2003, with a goal of reducing fourth quarter cash operating costs as low as $10 to $11 per barrel.

179 MILLION CUBIC FEET PER DAY AND GROWING

Suncor produces more natural gas than the company consumes, providing a price hedge that helps protect our bottom line from unpredictable energy costs. When natural gas prices are low, Suncor's oil sands and refining operations benefit from reduced energy costs, improving the company's margin on oil and refined products. When natural gas prices are high, increased revenues from natural gas production and sales help offset higher oil sands and refining production costs. This price hedge is an important part of Suncor's strategy to mitigate the risks and maximize the rewards of operating in a commodity industry. In 2003, Suncor's natural gas consumption is expected to grow to 120 million cubic feet (mmcf) per day from 110 mmcf per day in 2002. At the same time, production is expected to increase to 185 to 190 mmcf per day from the 179 mmcf per day average achieved in 2002.

A New Voyage

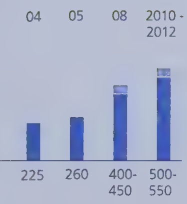
The goal is to more than double Suncor's oil sands production in the next decade. To get there, Suncor's Voyageur growth strategy* calls for development of a multi-phase in-situ recovery operation to feed an expanded, triple-train upgrader. When all the pieces are in place, Suncor's oil sands production capacity is targeted to grow to between 500,000 and 550,000 barrels per day by 2012 – generating about 15% of Canada's total projected crude oil production.

Stakeholder consultation, preliminary engineering and project development are under way for the Voyageur growth strategy and more detailed development plans are expected in 2003 as the first phase begins to move through the regulatory approval process.

The First Steps to 550,000

Every voyage starts with a single step. For Suncor, that step is a 35,000 barrel per day increase in production capacity with new bitumen supply from the first phase of the Firebag In-situ Oil Sands Project and the addition of a new vacuum tower to our upgrading facilities. The combined $1 billion project is on budget and on schedule, with first commercial oil production expected in 2004. This key step in Suncor's growth strategy is designed to ramp oil sands production capacity up to 260,000 barrels per day in 2005. Planning for the second phase of Firebag is under way with front-end engineering scheduled to be complete by mid-2003.

Oil Sands Planned Production Capacity
(thousands of barrels per day)



* All plans for Voyageur are subject to approval from regulators and Suncor's Board of Directors.

markets

multiple market connections

Suncor's refining and marketing strategy is aimed at building on the competitive advantage of having our oil sands production securely connected to customers in Canada and the United States, the largest crude oil market in the world. Suncor is connected to that market through a variety of sales agreements and our own refinery and retail network in Ontario. With a target of more than doubling Suncor's oil sands production in the next decade, we are pursuing new marketing opportunities and potential investments in refining assets to further integrate our upstream and downstream businesses.

One Big Market – Many Individual Customers

Suncor's marketing team connects our oil sands production to the crude oil and diesel markets in Canada, the United States and beyond. The goal is to match our mix of refinery-ready feedstock to the specific needs of individual customers.

By managing the contracts, transportation and product specifications, we are working with customer refineries to build stable long-term markets. Our objective is to provide high quality feedstock to our customers while also helping to realize more value on the sale of Suncor's products.

To provide a new window into energy product markets and add potential new revenues, Suncor launched an energy trading function in late 2002. Physical and financial trading activities are focused on the commodities Suncor produces.

TWO PATHS TO ENERGY DEVELOPMENT

While we produce hydrocarbon fuels to meet today's needs, Suncor is supporting the development of renewable energy for the future. We believe that market demand for renewable energy will continue to grow and that Suncor can become a leader in this industry.

The first major step in Suncor's five-year, $100 million plan for renewables was realized in 2002 with the official launch of the 11-megawatt SunBridge Wind Power Project, a partnership with Enbridge Inc. Building on the success of SunBridge, Suncor is targeting the launch of new wind power generation in 2003.

Refining the Custom Product Strategy

Suncor's refining operations take our custom product strategy a step further. Suncor's refinery in Sarnia, Ontario, provides gasoline, distillates and petrochemicals to industrial, commercial and retail customers, primarily in Ontario and Quebec. Refining and marketing operations help Suncor capture additional value from the products we produce today and develop a stable market for increasing oil sands production in the future.

As we look to future growth, Suncor is pursuing investment options to comply with new sulphur regulations for gasoline and diesel, while potentially leveraging desulphurization technology to increase processing capacity for sour crude streams.

High Performance, Low Emissions

Most of our refined product moves through wholly or partly owned retail networks, like the wholly owned Sunoco-brand network in Ontario, Canada's largest retailer of ethanol blended gasoline. Blending gasoline with ethanol, a cleaner burning fuel produced from renewable sources, reduces carbon monoxide and greenhouse gas emissions and boosts octane, making it the fuel of choice for many consumers. In 2003, Suncor plans to further increase consumer appeal with the redevelopment of our Sunoco retail network, providing premium products in a more attractive and convenient shopping environment.

Suncor is connected to the North American pipeline network, providing access to many customers for our growing oil sands production.

Management's Discussion and Analysis

This Management's Discussion and Analysis contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 38 for additional information. All financial information is reported in Canadian dollars unless noted otherwise. Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint venture investments, unless the context otherwise requires. "Notes" refers to the notes to Suncor's 2002 Consolidated Financial Statements.

The tables and charts in this document form an integral part of Management's Discussion and Analysis.

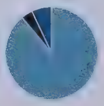
Suncor Overview and Strategic Priorities

Suncor Energy Inc. is an integrated Canadian energy company with its corporate head office located in Calgary, Alberta. Suncor's core business segment, Oil Sands, mines and upgrades oil sands near Fort McMurray, Alberta, to produce refinery feedstock and diesel fuel. Suncor's conventional Natural Gas business (NG) produces natural gas in Western Canada, providing revenues and creating a price hedge against the company's internal natural gas consumption. The Energy Marketing and Refining business (EM&R) refines crude oil and markets finished petroleum products to customers primarily in Ontario and Quebec, including retail customers in Ontario under the Sunoco brand.

Suncor's overall corporate strategy is based on:

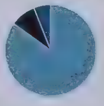
- Developing Oil Sands large resource base through mining and in-situ technology.
- Expanding Oil Sands facilities to increase the production of crude oil.
- Controlling costs through a strong operational focus, economies of scale and improved management of engineering, procurement and construction on major projects.
- Reducing risk associated with natural gas price volatility by producing volumes exceeding internal demand.
- Developing new marketing and refining opportunities that further integrate Suncor's upstream and downstream businesses.
- Managing environmental and social performance to earn continued support among community, government and other stakeholders for Suncor's ongoing operations and growth plans.

Net Earnings
(per cent)



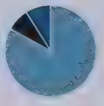
	02	01	00
Oil Sands	**89**	59	64
Natural Gas	**4**	24	20
Energy Marketing and Refining	**7**	17	16

Cash Flow Provided from Operations
(per cent)



	02	01	00
Oil Sands	**85**	52	62
Natural Gas	**9**	30	22
Energy Marketing and Refining	**6**	18	16

Capital Employed
(per cent)



	02	01	00
Oil Sands	**83**	64	64
Natural Gas	**8**	14	19
Energy Marketing and Refining	**9**	22	17

Net Earnings Components

Year ended December 31

($ millions)	2002	2001	2000
Net earnings before the following items:	**710**	424	414
Natural Gas divestments and restructuring	**—**	5	39
Stuart Oil Shale Project asset write-down	**—**	(3)	(80)
Sale of retail natural gas marketing business	**35**	—	—
Oil Sands project start-up costs[1]	**(2)**	(90)	(9)
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**8**	—	—
Impact of income tax rate reductions on opening future tax balances[2]	**10**	52	13
Net earnings	**761**	388	377

Cash Flow Provided from Operations Components

Year ended December 31

($ millions)	2002	2001	2000
Cash flow provided from operations before the following items:	**1 443**	1 061	1 009
Natural Gas divestments and restructuring	**—**	(1)	(9)
Oil Sands project start-up costs and overburden removal[1]	**(3)**	(229)	(42)
Cash flow provided from operations	**1 440**	831	958

(1) Project start-up costs refer to costs associated with Project Millennium in 2000 and 2001 and costs associated with the Firebag In-situ Oil Sands Project in 2002.

(2) See note 8.

The above tables are intended to enhance readers' understanding of some of the factors impacting Suncor's net earnings and cash flow provided from operations. For comparability purposes readers should rely on the reported net earnings and cash flow provided from operations, which are prepared and presented in the Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles.

Earnings Analysis

Net Earnings and Cash Flow Analysis

Net earnings for 2002 increased to $761 million from $388 million in 2001, primarily as a result of higher sales revenues from increased Oil Sands production and improved crude oil price realizations. Net earnings were also positively impacted by reduced project start-up costs at Oil Sands, a gain on the sale of EM&R's retail natural gas marketing business and an unrealized foreign exchange gain. These increases were partially offset by higher crude oil hedging losses and higher cash and non-cash operating expenses, financing costs and higher income taxes. The higher 2002 income taxes are partly a result of the positive earnings impact of enacted rate reductions in 2001 on the company's future income tax liabilities.

Cash flow provided from operations in 2002 was $1.44 billion, compared with $831 million in 2001. The increase was primarily due to the same factors that increased net earnings, excluding the gain on the sale of the company's retail natural gas marketing business. These favourable factors were partially offset by payments under Suncor's long-term employee incentive plan and increased overburden removal expenditures.

Consolidated Financial Results

Year ended December 31

($ millions)	2002	2001	2000
Net earnings	**761**	388	377
Cash flow provided from operations	**1 440**	831	958
Investing activities	**861**	1 680	1 607
Dividends			
Common shares	**77**	75	75
Preferred securities	**48**	48	47
Long-term debt	**2 686**	3 113	2 192
Return on capital employed (%)[1]	**14.6**	17.8	16.6
Return on capital employed (%)[2]	**13.8**	7.5	9.3

(1) Net earnings adjusted for after-tax long-term interest expense, divided by average capital employed. Average capital employed is the total of shareholders' equity and short-term and long-term debt, less capitalized costs of major projects in progress, at the beginning and end of the year, divided by two.

(2) Average capital employed includes capitalized costs related to major projects in progress.

Industry Indicators

(Average for the year unless otherwise noted.)	**2002**	2001	2000
WTI crude oil US$/barrel at Cushing	**26.10**	25.90	30.25
Canadian 0.3% par crude Cdn$/barrel at Edmonton	**40.75**	39.34	44.56
Light/heavy crude oil differential US$/barrel WTI @ Cushing/Bow River @ Hardisty	**5.95**	9.50	6.85
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**3.25**	4.40	3.90
Natural gas (Alberta spot) Cdn$/mcf at AECO	**4.05**	6.30	5.00
New York Harbour 3-2-1 crack US$/barrel(1)	**3.35**	4.45	5.45
Refined product demand (Ontario) percentage change over prior year	**0.8**(2)	(2.6)	2.6
Exchange rate: Cdn$:US$	**0.64**	0.64	0.67

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus one times the New York Harbour distillate margin and dividing by three.

(2) Estimate.

Consolidated Earnings Analysis

Revenues were $4.904 billion in 2002, compared to $4.199 billion in 2001. This increase was primarily the result of the following items:

- The **Project Millennium** expansion increased Oil Sands sales to an average 205,300 barrels per day (bpd) from 121,500 bpd in 2001. In addition, expanded hydrotreating capacity increased the sales mix percentage of higher value sweet crude oil and diesel fuel relative to lower value sour crude oil and bitumen to 62/38% in 2002 from 58/42% in 2001. Increased production and a higher value sales mix were the most significant factors in the overall increase in consolidated revenues.
- Suncor's overall crude oil price realization increased in 2002, averaging $33.65 per barrel (including the effect of pretax hedging losses of $243 million), compared to $29.17 per barrel in 2001 (including the effect of pretax hedging losses of $224 million). The increase was due to the strengthening of the West Texas Intermediate (WTI) benchmark price during 2002, higher Oil Sands production and the narrowing of sour crude oil and bitumen price differentials.
- Marketing revenue for third party crude oil and bitumen increased to $149 million in 2002 from $99 million in 2001. This marketing is undertaken to increase market intelligence and create new markets and customers for Suncor's proprietary crude oil.

The above factors were partially offset by the following:

- NG revenues in 2002 were $315 million, compared to revenues of $458 million in 2001. Suncor's average natural gas sales price decreased to $3.91 per thousand cubic feet (mcf) in 2002, from $6.09 per mcf in 2001.
- Sales in EM&R were $2.361 billion in 2002, compared to $2.588 billion in 2001. The decrease primarily reflects lower refining volumes, lower product prices and the impact of the sale of the retail natural gas marketing business in 2002.

Purchases of crude oil and products decreased to $1.298 billion in 2002 from $1.595 billion in 2001. The decrease was primarily due to reductions in EM&R's purchase requirements where improved refinery reliability, lower downstream sales levels and the sale of its retail natural gas marketing business, reduced the need for third party product purchases.

Operating, selling and general expenses were $1.292 billion in 2002, compared to $1.012 billion in 2001. The increase primarily relates to the higher expense of operating the expanded facilities at Oil Sands, including additional expenses related to unplanned maintenance shutdowns, employee benefits and insurance costs. These factors were partially offset by decreases in long-term incentive compensation costs (see note 11b), research and development costs and the absence of costs in 2002 related to the Stuart Oil Shale Project.

The continued weak performance of equity markets increased Suncor's employee future benefits cost to $52 million in 2002 from $30 million in 2001. Benefit costs are expected to increase to about $60 million in 2003. Annual costs beyond 2003 may change depending on market performance and/or changes in assumptions (see note 7).

Project Millennium

A $3.4 billion expansion of Suncor's Oil Sands mining and upgrading operations was commissioned in December 2001.

In 2002 insurance expenses were $22 million reflecting an increase of $14 million due to higher premiums as a result of tightening insurance market capacity. In 2003, the company anticipates a further $5 million increase reflecting continued tight capacity.

To mitigate its exposure to property and business interruption losses, the company has purchased insurance policies with a combined coverage up to US$1.150 billion, net of deductible amounts. The policies stipulate a property loss deductible of US$10 million per incident and a business interruption loss deductible per incident based on the greater of US$50 million or 30 days of gross earnings lost (as defined in the respective insurance policies). Gross earnings can be influenced by such factors as production levels and commodity prices.

Depreciation, depletion and amortization increased to $585 million in 2002, compared to $360 million in 2001. Depreciation on Project Millennium assets that came into service in January 2002 accounted for approximately half of the increase. Overburden amortization was also up in 2002 reflecting increased production levels, higher removal costs and, to a lesser extent, a higher composite life-of-mine overburden stripping ratio of 0.47 compared to 0.43 in 2001.

Exploration costs in 2002 increased to $26 million, compared to $22 million in 2001. The increase primarily relates to lease retention costs incurred with respect to the **Firebag In-situ Oil Sands Project**.

Royalty expenses decreased to $98 million in 2002, from $134 million in 2001, primarily due to lower natural gas prices. This decrease was partly offset by higher Oil Sands royalties due to higher production. The Oil Sands Crown royalty rate in 2002 was unchanged from 2001 at 1% of gross revenue.

Financing expenses (after capitalization of interest on projects) increased to $124 million in 2002, from $16 million in 2001. In 2001 interest of $103 million was capitalized on Project Millennium. Overall, financing costs (before capitalization of interest on projects) increased in 2002 to $155 million from $143 million in 2001, reflecting higher average debt levels in 2002.

Income tax expense increased to $383 million in 2002 from $125 million in 2001. Suncor's effective income tax rate in 2002 was 33%. This reflected a higher than anticipated 10% net reduction related to the federal resource allowance deduction and non-deductible Crown royalties (see note 8). Suncor's 2001 effective income tax rate was 24%, primarily reflecting a future income tax reduction of 6% related to federal resource allowance and non-deductible Crown royalties, as well as the effect of an 11% reduction in federal and provincial income tax rates on the revaluation of future income taxes.

Suncor anticipates its effective tax rate in 2003 will be about 35%. The effective rate can vary depending on changes in such factors as enacted tax rates, the resource allowance deduction and non-deductible Crown royalties. Based on prior years' investment levels and planned future investment plans, Suncor does not expect its upstream operations to be cash taxable until 2010. This expectation can change depending on such factors as commodity prices, profitability, capital investments and changes in tax rates and laws.

Dividends

During 2002, Suncor's annual common share dividend, after accounting for the two-for-one stock split in May 2002, was $0.17 per share, unchanged from 2001. Dividend levels are reviewed quarterly in light of Suncor's growth-related initiatives, financial position, financing requirements, cash flow and other factors considered relevant by the Board of Directors.

Corporate Office Expenses

Corporate office after-tax expenses increased to $128 million in 2002 from $92 million in 2001. The increase reflects the higher financing costs discussed above, partially offset by lower long-term compensation costs and lower research and development expenditures.

The corporate office had a net cash deficiency of $225 million in 2002, compared to $165 million in 2001. The increase is a result of the payments associated with the long-term compensation plan and higher capital expenditures, partially offset by lower net income tax payments.

Firebag In-situ Oil Sands Project

Firebag is designed to recover bitumen from deep oil sands deposits using horizontal drilling technology with minimal surface disturbance.

Trading Activities

In 2002, Suncor's Board of Directors approved commencement of energy trading activities and after developing an appropriate control framework, the company began limited trading activities in November. Trading activities are principally focused on the commodities the company produces, adding potential for new revenue and providing a new window into energy product markets. The company uses the mark-to-market method of accounting for the new energy trading activities. Under mark-to-market accounting, physical and financial energy contracts are recorded at fair value at each balance sheet date. The net gain or loss from the revaluation of these contracts is recorded in the Statement of Earnings for the period. Net trading losses were negligible for the period ended December 31, 2002.

A separate risk management function directs and monitors practices and policies and provides independent verification and valuation of Suncor's trading and marketing activities.

Critical Accounting Policies

Suncor's critical accounting policies are defined as those that are both important to the portrayal of the company's financial position and operations and require management to make judgments based on underlying estimates and assumptions about future events and their effects. Underlying estimates and assumptions are based on historical experience and other factors that are believed by management to be reasonable under the circumstances. These estimates and assumptions are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Suncor's operating environment changes. The company believes the following are the most critical accounting policies and estimates used in the preparation of its consolidated financial statements. For information concerning the company's other significant accounting policies, see "Summary of Significant Accounting Policies" on page 41 of the Consolidated Financial Statements.

Property, Plant and Equipment

Suncor accounts for upstream exploration and production activities using the "successful efforts" method. The application of the successful efforts method of accounting requires Suncor's management to determine the proper classification of activities designated as developmental or exploratory, which ultimately determines the appropriate accounting treatment of the costs incurred. The results from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the exploratory costs are written off and reported as "dry hole" costs (see note 18). Despite this, properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities insufficient to be economic. Tests of impairment of capitalized properties are based on estimates of future cash flow from the properties. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating costs. Where management assesses that a property is fully or partially impaired, the book value of the property is either completely removed from the company's records ("written off") or partially removed from the company's records ("written down").

The company's plant and equipment, including upgrading and refining assets, are amortized on a straight-line basis over the estimated useful life of the assets. The company determines useful life based on prior experience with similar assets and, as necessary, in consultation with others who have expertise with the assets in question. However, the actual useful life of the assets may differ from management's original estimate due to factors such as technological obsolescence, regulatory requirements and maintenance activity.

Employee Future Benefits

The company provides a range of benefits to its employees and retired employees, including pensions and other post-retirement health and dental care benefits as described in note 7. The determination of obligations under the company's benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. As a result, the accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used, as described in note 7.

Reclamation and Environmental Remediation Costs

Suncor's reclamation and environmental remediation costs represent the costs of reclaiming the environment or restoring a site to a useful and acceptable condition, as determined by statutory or regulatory authorities, by contractual agreement, or by Suncor management. The scope of the activities and the nature of the costs are normally outlined in the current reclamation or environmental remediation plan. These include costs specifically related to the reclamation or environmental remediation project and any other costs that can be clearly identified with the project.

Estimated reclamation costs at Oil Sands and NG are accrued on the unit of production basis based on proved and probable reserves. Estimated environmental remediation costs in EM&R are accrued in the period for those sites where assessments indicate that such work is required. Reclamation and environmental remediation costs are charged against earnings and reported as operating, selling and general expenses.

On an annual basis at Oil Sands and NG, the most probable costs of reclamation are estimated in current-year dollars, based on current information, the estimated timing of remedial actions, existing regulatory requirements and technology. If it is not possible to determine a most probable estimate, the lowest estimate in the range of equally probable estimates is used.

The greatest area of judgment and uncertainty with respect to the company's reclamation estimates relates to its Oil Sands mining leases where there is a requirement to provide for land productivity equivalent to predisturbed conditions. To reclaim tailings ponds, Suncor is using a process referred to as consolidated tailings. At this time no ponds have been fully reclaimed using this technology, although work is under way. The success and time to reclaim the tailings ponds could increase or decrease the current reclamation cost estimates. The company continues to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

Suncor currently estimates remaining cash reclamation expenditures will be $610 million over the next 40 years. A 10% change in this estimate could impact Oil Sands annual reclamation provision by $3 million pretax.

Reserve Estimates

On an annual basis Suncor engages Gilbert Laustsen Jung Associates Ltd. (GLJ), independent petroleum consultants to either audit (Oil Sands mining leases) or conduct independent evaluations (Firebag in-situ and NG's conventional leases) of the company's reserve[1] estimates. The accuracy of any reserve estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data gathered over time.

Reserve Reconciliation[1]

	Oil Sands Mining Leases (millions of barrels of gross synthetic crude oil)			Firebag In-situ Leases (millions of barrels of gross synthetic crude oil)			Natural Gas Leases (billions of gross cubic feet)
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved
December 31, 2000	422	2 034	2 456	—	—	—	797
Additions	—	—	—	—	1 664[2]	1 664[2]	27
Revisions	(1)	(5)	(6)	—	—	—	(3)
Production	(45)	—	(45)	—	—	—	(65)
Dispositions	—	—	—	—	—	—	(1)
December 31, 2001	376	2 029	2 405	—	1 664	1 664	755
Additions	3	45	48	144	32	176	53
Revisions	54	(511)	(457)	—	—	—	(35)
Production	(75)	—	(75)	—	—	—	(65)
Dispositions	—	—	—	—	—	—	(2)
December 31, 2002	**358**	**1 563**	**1 921**	**144**	**1 696**	**1 840**	**706**

(1) In their audits or evaluations of Suncor's mining and in-situ leases, GLJ state they believe there is a 90% probability and 50% probability that proved and probable reserves estimates, respectively, will be exceeded. Accordingly, Suncor's probable oil sands reserves have not been further reduced for risk associated with obtaining production from such reserves. GLJ's mining and in-situ reserves estimates consider recovery from leases for which regulatory approvals have been granted, and are stated before the deduction of Crown and other royalties. Suncor reports its proved and probable reserves in accordance with Canadian disclosure requirements. The terms "proved" and "probable" reserves have the meanings ascribed to them in National Policy 2B of the Canadian Securities Administrators. U.S. companies are prohibited from disclosing estimates of probable reserves for non-mining properties in filings with the United States Securities and Exchange Commission. As a result, Suncor's reserve estimates may not be comparable to those made by U.S. companies.

(2) For Firebag reserves, the additions in 2001 and the year-end 2001 closing balance have been adjusted from a bitumen value of 2.029 billion barrels based on assumed coker (synthetic crude) yields of between 80% and 82%.

Oil Sands Mining Reserves

Proved and probable oil reserves estimates on Oil Sands mining leases are based on a detailed geological assessment, including drilling density and laboratory tests. Estimates also consider current production capacity and upgrading yields, current mine plans, operating life and regulatory constraints.

Subsequent to year-end 2002, management completed its reserve review and received the report of the independent consultants. As a result of this review, there was a revision to Suncor's probable Oil Sands mining reserves. Approximately half of this probable reserve revision reflects management's decision not to mine in less economic areas, as permitted by regulatory changes. The company could decide to mine these leases in the future. The balance of the revision incorporates additional knowledge and understanding of the Millennium mine.

Management will reflect the impact of the negative reserve revision in Oil Sands results beginning in 2003.

Firebag In-situ Reserves

For the Firebag Project, reserve estimates increased in 2002 primarily through the recognition of 144 million barrels of proved non-producing reserves. This increase reflects reclassification of a portion of probable reserves to proved status, now that the first stage of construction of the project is nearly complete and other similar industry projects have demonstrated commercial success of the in-situ process.

Natural Gas Reserves

Suncor's NG proved reserves declined in 2002 as a result of production in the year and revisions due to operating experience. These factors were only partially offset by drilling additions.

Overburden

As part of the process of mining oil sands, it is necessary to remove surface material such as muskeg, glacial deposits and sand. Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, the quantity of overburden removed in a given period may not bear any relationship to the quantity of oil sands actually mined in the period.

In order to ensure a proper matching of costs with revenues (such that each tonne of oil sands mined is allocated a proportionate share of overburden removal costs), the company has adopted the deferral method of accounting for overburden removal costs, whereby all such costs are initially set up as a deferred charge (see note 3).

To allocate the deferred overburden charges, a life-of-mine approach has been adopted for each mine pit, relating the removal of all overburden to the mining of all of the oil sands ore on leases where there is regulatory approval. By adopting this approach, an overburden stripping ratio is calculated that allows for the matching of revenues and expenses such that overburden removal costs are averaged over the life of the mine. Over time, through a combination of increased mine areas (as with the Millennium mine expansion), additional drilling activity and operational experience, the company has seen its stripping ratios vary, which can increase or decrease the overburden amortization costs charged to the earnings statement (see Oil Sands Overview on page 27).

Outlook

Production Growth at Oil Sands

Suncor is targeting an increase in production capacity to 260,000 bpd in 2005. Work is also under way to finalize plans for the Voyageur growth strategy, which has a goal of increasing production to 500,000 bpd to 550,000 bpd by 2010 to 2012. (For further details, see Oil Sands Overview on page 27).

Integration

The company continues to assess downstream integration opportunities to capture greater long-term value from its oil sands production. Natural gas production and the use of the natural gas in Suncor's operations is also a component of the corporate integration strategy (see Natural Gas Overview on page 32 and Energy Marketing and Refining Overview on page 35).

Capital Spending

In 2003, Suncor plans capital spending of more than $1 billion, with $496 million directed towards Oil Sands growth projects. This includes spending to support stage one of the Firebag Project as well as construction of a new vacuum unit for the Oil Sands upgrading facilities. Another $215 million will be spent to maintain Oil Sands operations, which includes completing a maintenance shutdown. In the downstream, the company plans to spend $145 million in 2003. The bulk of this spending will be allocated towards projects at Suncor's Sarnia refinery to meet pending gasoline and distillate desulphurization initiatives and integrate production streams from Oil Sands. Spending will also be directed to the Sunoco retail network to help maintain its competitive position in the Ontario market. The balance of Suncor's capital budget for 2003 is allocated to support the company's goal of growing

natural gas production ($160 million), and fund technology upgrades and renewable energy investments ($35 million).

Climate Change

Suncor's effort to reduce greenhouse gas emissions is reflected in its pursuit of greater internal energy efficiency, investment in emissions offsets and carbon capture research and development.

Suncor continues to consult with governments about the impact of the Kyoto Protocol and plans to continue to actively manage its greenhouse gas emissions. Suncor currently estimates that in 2010 the impact of the **Kyoto Protocol** on Oil Sands cash operating costs would be about $0.20 to $0.27 per barrel. This estimate assumes a reduction obligation of 15% from 2010 **business-as-usual energy intensity** and that the maximum price for carbon credits would, as the Government of Canada indicated in late 2002, be capped at $15 per tonne of carbon dioxide equivalent. Based on these assumptions, Suncor does not currently anticipate the cost implications of the Kyoto Protocol will have a material impact on its business or future growth plans. The ultimate impact of Canada's anticipated implementation of the Kyoto Protocol, however, remains subject to numerous risks, uncertainties and unknowns. These include the outcome of discussions between the federal and provincial governments, the form, impact and effectiveness of implementing legislation, the ultimate allocation of reduction obligations among economic sectors, and other details of Canada's implementation plan, as well as international developments. In addition, the Government of Canada has not yet indicated what, if any, limitations will be placed on the price of carbon credits after 2012. It is not possible to predict how these and other Kyoto related issues will ultimately be resolved.

Renewable Energy

As the company expands its hydrocarbon-based businesses, Suncor expects to continue to work toward the development of renewable energy, which has the potential to reduce environmental impacts and create additional business investment opportunities. This strategy was reflected in the company's announcement to invest $100 million between 2000 and 2005 on renewable energy projects.

In 2002, Suncor officially launched the SunBridge Wind Power Project, a partnership with Enbridge Inc. In 2003, Suncor's goal is to launch investment plans for additional wind power projects.

Risk/Success Factors Affecting Performance

Suncor believes that while its business strategies will provide strategic advantages, they also present issues that will require prudent risk management. The issues Suncor must manage include, but are not limited to, commodity prices, environmental regulations, stakeholder support for growth plans, regional labour issues and the further specific issues discussed under Risk/Success Factors Affecting Performance for each Suncor business as well as the more detailed risk factors described in Suncor's most recent Annual Information Form/Form 40-F, filed with securities regulatory authorities.

Commodity Prices

Suncor's future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by many factors including global and regional supply and demand, worldwide political events and the weather. These factors, among others, can result in a high degree of price volatility. For example, from 2000 to 2002 the monthly average price for benchmark WTI crude oil ranged from a low of US$19 per barrel to a high of US$34 per barrel. During the same period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$1.89 per mcf to a high of US$9.79 per mcf.

Crude oil and natural gas prices are based on a U.S. dollar benchmark that results in Suncor's realized prices being influenced by the Canadian/U.S. currency exchange rate, creating an element of uncertainty for the company. However, the impact of foreign exchange fluctuations on earnings is partially mitigated by the company's U.S. dollar denominated long-term debt and preferred securities. The company estimates that a

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Kyoto Protocol
An international agreement to reduce emissions of greenhouse gases. Canada ratified the Kyoto Protocol in December 2002.

business-as-usual energy intensity
Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 1990.

$0.01 change in the Cdn$:US$ exchange rate would have a $10 million after-tax impact on net earnings with respect to U.S. dollar denominated long-term debt and a $3 million after-tax impact on net earnings attributable to common shareholders related to U.S. dollar denominated preferred securities.

During 2002, the fluctuation of the Canadian dollar against the U.S. dollar resulted in a net $8 million after-tax unrealized foreign exchange gain on the company's U.S. dollar denominated long-term debt and a $1 million after-tax unrealized foreign exchange gain with respect to Suncor's U.S. dollar denominated preferred securities.

Hedging

Suncor cannot control or accurately predict the prices of crude oil or natural gas, or currency exchange rates. For this reason, the company has a hedging program that fixes a price or range of prices for crude oil for a percentage of Suncor's total production (see note 5). Suncor's risk management objective with its hedging program is to reduce its exposure to market volatility and support the company's ability to finance growth.

The Audit Committee and the Board of Directors meet with management regularly to assess Suncor's hedging thresholds in light of its price forecast and cash requirements. To add more certainty to Suncor's ability to finance future capital programs and repay debt, the Board authorized hedging approximately 35% of the company's crude oil volumes in 2003 and up to 30% for the period 2004 to 2006. In 2002, hedging decreased Suncor's earnings by $160 million. In 2001, hedging decreased earnings by $148 million.

Crude Oil Hedging Program
(at December 31, 2002)

	03	04	05	06	07
Current annual limits thousands of barrels per day (kbpd)	81	68	73	75	78
Annual crude oil hedged (kbpd)	78	36	21	—	—
Percentage of annual crude oil hedged	36	16	9	—	—
Hedged price* – Cdn$ per barrel	35.15	35.21	34.51	—	—

* The weighted average price is based on swaps and the floor price of costless collars outstanding at December 31, 2002. See note 5b.

Environmental Regulation

Environmental legislation affects nearly all aspects of Suncor's operations, imposing certain standards and controls on activities relating to oil and gas mining and conventional exploration, development and production. Environmental legislation also affects refining, distribution and marketing of petroleum products and petrochemicals and requires companies engaged in those activities to obtain necessary permits to operate. Environmental assessments and approvals are required before initiating most new projects or undertaking significant changes to existing operations.

In addition to these specifically known requirements, Suncor expects changes to environmental legislation could impose further requirements on companies operating in the energy industry. Some of the issues include the possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; issues relating to global climate change, including the uncertainties and risks associated with Canada's implementation of the Kyoto Protocol and uncertainties associated with predicting emission intensity levels from Suncor's future production; and other potential impacts of government regulation in areas such as land reclamation and restoration, water quality and reformulated fuels to support lower vehicle emissions. Changes in environmental regulation could have an adverse effect on Suncor in terms of product demand, product formulation and quality, methods of production and distribution and operating costs. The complexity of these issues makes it difficult to predict their future impact on the company. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations.

Other Factors

Other critical factors affecting Suncor's financial results include volumes and margins of refined product sales, success of the natural gas exploration and development program including coal bed methane initiatives, interest rates and the company's ability to manage both day-to-day operating costs as well as reclamation and remediation costs and project costs on existing and future projects.

Sensitivity Analysis

	2002 Average	Change	Approximate Change in Pretax Cash Flow from Operations	Approximate Change in After-tax Earnings
Oil Sands				
Price of crude oil ($/barrel)	Cdn$ 33.65	US$1.00	81	54
Sweet/sour differential ($/barrel)	Cdn$ 7.86	US$1.00	28	19
Sales (barrels/day)	205 300	1,000	11	7
Natural Gas				
Price of natural gas ($/mcf)	Cdn$ 3.91	0.10	5	2
Production of natural gas (mmcf/d)	179	10	11	4
Energy Marketing and Refining				
Retail gasoline margins (cents/litre)	6.6	0.1	2	1
Refining/wholesale margin (cents/litre)	4.8	0.1	5	3
Consolidated				
Exchange rate: Cdn$:US$	0.64	0.01	34	32
Interest rate – on variable rate borrowings	3.1%(1)	1%	14	9

(1) Borrowing with interest at weighted average variable rates of 3.1% at December 31.

The sensitivity analysis shows the main factors affecting Suncor's annual pretax cash flow from operations and after-tax earnings (in Cdn$ millions) based on actual 2002 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2002 results. A change in any one factor could compound or offset other factors.

Liquidity and Capital Resources

Net debt decreased to $2.671 billion at the end of 2002, a reduction of $462 million, excluding the $10 million effect of an unrealized foreign currency translation gain. As at December 31, 2002, the company had fixed-term debt (before the effect of interest rate swap transactions) of approximately $1.8 billion, with the balance comprised of variable rate borrowings and fixed-term capital leases.

Suncor has sufficient lines of credit to meet working capital requirements and will continue to monitor capital markets for opportunities to refinance bank debt with long-term debt. Suncor's undrawn lines of credit at December 31, 2002 were approximately $1.1 billion.

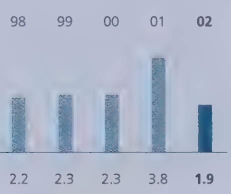
In the first quarter of 2002, Suncor issued US$500 million of 7.15% unsecured notes due 2032 from a US$1 billion unallocated shelf prospectus. The net proceeds from the sale were used to repay commercial paper and bank borrowings. Also in the first quarter of 2002, Suncor filed a shelf prospectus with Canadian securities regulatory authorities, enabling it to issue up to a further $500 million in medium-term notes in Canada if required. No notes were issued under the Canadian shelf prospectus during the year.

Interest expense continues to be influenced by the composition of the company's debt portfolio (in particular its variable rate borrowings) with short-term floating interest rates at historic lows. To manage its fixed versus floating rate exposure, Suncor has entered into a number of interest rate swaps with investment grade counterparties, resulting in the swapping of $490 million of net fixed rate debt to variable rate borrowings.

Suncor's capital resources at December 31, 2002, consist primarily of cash flow provided from operations, available lines of credit and the remaining debt and equity capacity under the shelf prospectuses. Suncor's level of earnings and cash flow provided from operations depends on many factors, including commodity prices, production levels and downstream margins. Suncor believes it will be able to fund its 2003 capital spending program of approximately $1 billion from the above-noted capital resources.

Debt reduction is a priority for Suncor as it prepares for the next stages of growth. Management believes a phased approach to future growth projects should improve its ability to manage project costs and provide further opportunities for debt reduction. This approach, along with anticipated higher Oil Sands sales levels and the hedging of approximately 35% of crude oil

Ratio of Net Debt to Cash Flow Provided from Operations
(times)



production in 2003, should allow Suncor to continue reducing both the absolute debt level and the ratio of net debt to cash flow provided from operations. Suncor's long-term target for this ratio is 2.0 times at mid-cycle commodity pricing. At the end of 2002 this ratio was 1.9 times compared to 3.8 times as at December 31, 2001. The decrease is due to a combination of increased cash flow from operations, lower year-end net debt and lower project spending with the completion of Project Millennium.

Aggregate Contractual Obligations and Off-balance Sheet Financing

		Payments Due by Period			
($ millions)	Total	2003	2004 – 2005	2006 – 2007	Later years
Commercial paper	548	—	—	548	—
Bank debt	199	—	199	—	—
Fixed-term debt and capital leases	1 939	12	223	406	1 298
Operating lease agreements and pipeline capacity and energy services commitments	5 207	216	413	409	4 169
Total	**7 893**	**228**	**835**	**1 363**	**5 467**

At December 31, 2002 Suncor had three off-balance sheet arrangements with Special Purpose Entities (SPE) as described in note 9c. In 2002, the company had in place a securitization program to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less to a third party SPE. In 1999, the company sold 2,130,000 barrels of its crude oil inventory for $49 million to a SPE while retaining use of the inventory for its operations through a five-year agreement. Also in 1999, the company entered into an equipment sale and leaseback arrangement with a SPE for proceeds of $30 million.

The company is currently in the process of assessing the impact of recently issued U.S. accounting interpretations and will assess new Canadian accounting interpretations when issued. These new standards may require consolidation of one or more of the above-noted off-balance sheet arrangements.

Planning Assumptions

	2002 Actual Average for the year	Current Plan Average next 3-year range	2001 Plan Average next 3-year range
Crude oil – WTI US$ per barrel	**26.10**	20.00 – 22.00	19.00 – 21.00
Natural gas – US$/thousand cubic feet @ Henry Hub	**3.25**	3.40 – 3.60	3.00 – 3.45
Exchange rate: Cdn$:US$	**0.64**	0.65	0.65 – 0.69

The above are planning assumptions and are not estimates or predictions of actual future events or circumstances. This table does not incorporate potential cross-relationships, and does not necessarily accurately predict future results.

Recently Issued Accounting Standards

For a discussion of recently issued Canadian accounting standards relating to "Hedging Relationships" and "Asset Retirement Obligations," see "Summary of Significant Accounting Policies" on page 41.

Oil Sands Overview

Suncor's Oil Sands business, located near Fort McMurray, Alberta, continues to be the primary focus of the company's development plans throughout the next decade. The business mines oil sands ore, extracting and upgrading the bitumen into refinery feedstock and diesel fuel.

Oil Sands strategy is based on:

- Increasing oil production by applying proven technologies to develop Suncor's **oil sands** resources.
- Reducing costs through application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.
- Building strategic business relationships to mitigate downstream risk and capture value from the production and marketing of synthetic crude oil and by-products.

Summary of Results

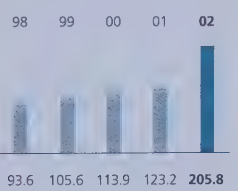
Year ended December 31

($ millions unless otherwise noted)	**2002**	2001	2000
Revenue	**2 659**	1 385	1 336
Production (thousands of bpd)	**205.8**	123.2	113.9
Average sales price ($/barrel)	**33.65**	29.17	31.67
Net earnings	**793**	283	315
Cash flow provided from operations	**1 480**	486	655
Total assets	**6 896**	6 409	5 079
Investing activities	**630**	1 476	1 715
ROCE (%)(1)	**16.8**	20.1	22.8
ROCE (%)(2)	**15.6**	6.4	10.6

(1) Excluding capitalized costs related to major projects in progress.

(2) Includes capitalized costs related to major projects in progress.

Production
(thousands of bpd)

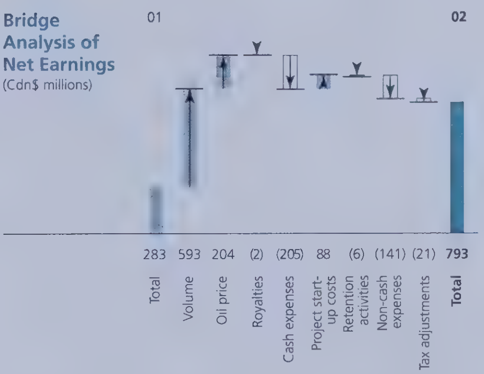


Analysis of Net Earnings

Oil Sands net earnings were $793 million in 2002, compared with $283 million in 2001. Increased earnings were primarily the result of higher sales revenues from both increased production and the strengthening of benchmark crude prices over the course of the year. Net earnings also benefited from an improved sales mix of higher value sweet crude oil and diesel fuel relative to lower value sour crude oil and bitumen, lower product differentials and the absence of Project Millennium start-up costs. Partially offsetting these factors were higher cash and non-cash expenses, higher hedging losses, and a higher effective tax rate in 2002 compared to 2001. The 2001 effective tax rate was lower due to the positive earnings impact of enacted provincial rate reductions in 2001 applied to Oil Sands future income tax liabilities.

During 2002, Oil Sands production increased to an average of 205,800 barrels per day (bpd), compared to 123,200 bpd in 2001. The higher production resulted in

Bridge Analysis of Net Earnings
(Cdn$ millions)



Higher sales volumes and prices contributed to an increase in earnings.

oil sands
Oil sands are naturally occurring mixtures of bitumen, water, sand and clay.

increased average sales of 205,300 bpd, compared to 121,500 bpd in 2001. The impact of higher sales levels increased year-over-year net earnings by $593 million.

The increase in production and sales was primarily the result of Suncor's Project Millennium expansion, which was commissioned in December 2001. Project Millennium increased Oil Sands production capacity to 225,000 bpd. However, challenges in bringing the new Millennium facilities to capacity during the first half of 2002 impacted production and sales levels for the year. Oil Sands production steadily climbed to 227,600 bpd in the fourth quarter from the first quarter average of 179,300 bpd. By the end of 2002, the Millennium assets were performing well with what management believes were relatively few technical issues for a plant of its scale and complexity.

Net earnings were also favourably impacted by an increase in Oil Sands crude oil price realization that averaged $33.65 per barrel (including pretax hedging losses) in 2002 compared to $29.17 per barrel (including pretax hedging losses) in 2001.

The increase in average price realization was due to three factors:

- A strengthening of the 2002 WTI benchmark price throughout the year, which corresponded with increasing production. On an overall basis, the WTI benchmark price averaged US$26.10 per barrel in 2002, compared to US$25.90 per barrel in 2001.
- Improved sweet crude oil and diesel product mix, which increased to 62% of total Oil Sands production from 58% in 2001.
- Narrowing of sour crude oil and bitumen price differentials partially offset by the narrowing of the diesel premium.

The impact of these favourable factors increased Oil Sands 2002 net earnings by $204 million.

Royalties

Crown royalties in effect for Oil Sands mining operations require payments to the Government of Alberta of 25% of net revenues less allowable costs (including the deduction of capital expenditures), subject to a minimum payment of 1% of gross revenues before hedging activity. In both 2002 and 2001, Oil Sands was subject to the minimum 1% rate. However, as a result of increased sales levels, Crown royalties increased to $28 million in 2002 from $15 million in 2001.

Based on current assumptions in Suncor's annual planning cycle relating to future oil prices, production levels, operating costs and capital expenditures, the company expects to continue to pay the minimum 1% rate until 2010.

The Firebag in-situ leases, which are not yet in production, will be under the same royalty regime as Suncor's mining leases.

In addition to Crown royalties, Suncor paid royalties to Anadarko Petroleum Corporation (Anadarko) for mining a lease on which Anadarko had a royalty interest. Royalties paid to Anadarko were $5 million in 2002, compared to $15 million in 2001. Mining on the lease was substantially completed in 2002 and Suncor does not anticipate paying significant royalties to Anadarko in future years. In 2002, Suncor commenced mining on a lease subject to a royalty in favour of Petro-Canada, calculated at 1.5% of the net sale proceeds from the lease. No royalties were payable to Petro-Canada in 2002.

The increase in Crown and other royalties year-over-year reduced Oil Sands after-tax income by $2 million.

Expenses

Cash operating costs (excluding project start-up costs) increased to $829 million compared to $493 million in 2001, reducing Oil Sands after-tax earnings by approximately $205 million. The increase was primarily due to higher structural operating costs associated with the increase in production capacity, including higher natural gas consumption, maintenance and increased labour costs. Oil Sands also incurred additional costs related to a two-day power outage in the first quarter, work performed on the new Millennium facilities during the first half of the year and an unplanned maintenance shutdown in the third quarter of 2002.

Project start-up costs were $3 million in 2002, compared to $141 million in 2001. The decrease reflects reduced costs resulting from the completion of Project Millennium. The decrease resulted in an after-tax earnings improvement of $88 million.

During 2002, Oil Sands incurred exploration costs of $9 million related to retention activities on its Firebag leases, reducing Oil Sands after-tax earnings by $6 million. There were no such costs in 2001. During 2003, Oil Sands anticipates a similar level of costs pertaining to its Firebag leases.

Non-cash charges (depreciation, depletion and amortization) increased to $450 million in 2002 from $233 million in 2001. The increase was primarily due to additional depreciation related to the Project Millennium assets and $99 million in higher overburden amortization costs. These factors decreased after-tax earnings by $141 million.

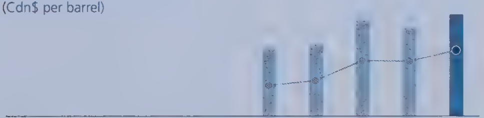
The higher overburden amortization in 2002 primarily reflects increased production levels, higher removal costs and, to a lesser extent, a higher composite life-of-mine overburden stripping ratio.

In 2002, Oil Sands composite stripping ratio was 0.47 cubic metres of overburden for every tonne of ore mined. In 2001 this ratio was 0.43 cubic metres per tonne.

The higher composite stripping ratio in 2002 was a result of a higher proportion of production from Millennium, which had a higher stripping ratio (0.58) than Steepbank (0.36). In 2003, the Millennium mine pit ratio will change to 0.56. Over time, with a greater proportion of total mining production expected to come from Millennium, and assuming no other changes, the composite stripping ratio will approach the estimated Millennium life-of-mine ratio of 0.56. This will increase the overburden amortization cost.

Partially offsetting expected higher overburden amortization costs is an expected improvement in bitumen recovery. The company estimates that on a life-of-mine basis, the bitumen recovery per tonne of ore in the Millennium mine pit will be approximately 0.69 barrels, compared to 0.61 in Steepbank.

Operating Margins
(Cdn$ per barrel)

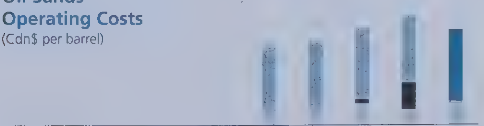


	98	99	00	01	**02**
■ Selling price	22.18	23.84	31.67	29.17	**33.65**
● Cash margin	9.25	10.75	16.80	16.60	**19.90**

Selling price – The average price from the sale of crude oil, including the impact of hedging activities.

Cash margin – The difference between the selling price received for products sold and cash operating cost per barrel (excluding start-up costs) plus royalties per barrel.

Oil Sands Operating Costs
(Cdn$ per barrel)



	98	99	00	01	**02**
■ Cash operating cost	11.75	11.70	12.55	11.90	**13.20**
■ Project start-up costs	—	—	1.00	5.10	**0.05**
Total cash cost	11.75	11.70	13.55	17.00	**13.25**
Non-cash cost	2.25	3.35	3.70	2.60	**3.90**
Total	14.00	15.05	17.25	19.60	**17.15**

Cash operating costs were higher than the company's original goal of $10.00 to $10.50 per barrel and increased over 2001. The increase is primarily attributed to higher costs and lower than anticipated sales.

Due to the use of judgment and the extended time frame associated with the company's stripping ratio and bitumen recovery estimates, actual results may differ and these differences may be material.

Net Cash Surplus Analysis

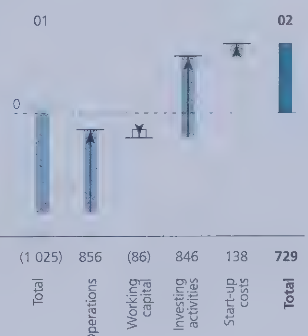
Cash flow provided from operations was $1.48 billion in 2002, compared with $486 million in 2001. The increase was primarily due to the factors that increased net income as described above, partially offset by an increase in overburden expenditures.

Oil Sands working capital increased by $121 million in 2002, compared to an increase of $35 million in 2001. This $86 million year-over-year increase in working capital is primarily due to higher trade receivables as a result of both higher sales levels and a higher WTI benchmark at year-end 2002, partially offset by increased accrued hedging losses.

Investing activities decreased to $630 million in 2002 from $1.476 billion in 2001. The decrease was primarily due to lower capital expenditure requirements in 2002 with the completion of Project Millennium in 2001, partially offset by increased capital spending on the Firebag Project and related upgrader improvements of $408 million.

These combined factors resulted in a net cash surplus of $729 million in 2002, compared to a net cash deficiency of $1.025 billion in 2001.

Bridge Analysis of Net Cash Surplus
(Cdn$ millions)



Higher sales volume and realized price increased cash flow from operations. Decreased capital spending was slightly offset by an increase in working capital mainly due to higher trade receivables.

Outlook

The foundation of Suncor's growth plans is the resource base estimated to be in place on the company's oil sands leases. Independent estimates currently place total Oil Sands mining and in-situ recoverable bitumen **resources** at nearly 13 billion barrels including proved and unrisked probable in-situ and mining bitumen reserves estimated at approximately 4.7 billion barrels.

Suncor's future plans for Oil Sands remain focused on activities expected to increase production, decrease operating costs and improve environment, health and safety performance.

Production Plans

In 2003, production at Oil Sands is expected to average about 215,000 bpd. Production will be lower than the plant's 225,000 bpd capacity as a result of a 30-day maintenance shutdown, currently scheduled for the second quarter of 2003. The maintenance work will result in the shutdown of Upgrader #1. Production at Oil Sands is expected to average 110,000 bpd during the maintenance period. Costs for the maintenance shutdown are budgeted at $65 million to $70 million. These costs will be amortized over the period to the next planned shutdown, tentatively scheduled for 2005 or 2006.

During the maintenance shutdown, Suncor plans to tie a new fractionator into the upgrader complex, replacing the existing unit, which has been in operation since 1967.

Operating Costs

Reducing operating costs is a strategic priority for Oil Sands. The business's goal for 2003 is to reduce its average cash operating cost to $12.50 per barrel (excluding project start-up costs). This goal assumes a production rate average of 215,000 bpd, reflecting both the production and cost impact of the 30-day maintenance shutdown.

The company expects production rates will improve following the maintenance shutdown. The higher production, combined with cost-saving initiatives Oil Sands expects to implement, have resulted in a target of reducing cash operating costs during the fourth quarter of 2003 to as low as $10 to $11 per barrel (excluding project start-up costs).

Suncor's cash operating cost goals assume the price of natural gas will average about US$3.60 per thousand cubic feet during 2003. Continued high natural gas prices will pose a significant challenge to reaching year-end cost reduction goals. A change of US$1 per thousand cubic feet in the Henry Hub price of natural gas would result in a change of approximately Cdn$0.50 per barrel to cash operating costs. However, because Suncor is a net producer of natural gas, continued high prices will have a positive impact on earnings.

Beyond 2003, Oil Sands will continue to pursue cost reductions while also developing and integrating new technologies and processes that have the potential to further improve competitiveness.

Firebag In-situ Oil Sands Project

The first stage of the Firebag In-situ Oil Sands Project is expected to begin commercial bitumen production in 2004. Full production from the first stage, targeted at 35,000 barrels per day of bitumen, is not expected until mid-2005. Combined with associated investments in the upgrader, the Firebag Project is expected to contribute to a planned increase in Oil Sands production capacity to 260,000 bpd in 2005, at a total cost of approximately $1 billion. The project remains on schedule and on budget. Engineering is under way on the second stage of Firebag.

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resources

Resources include proved and probable reserves (see page 21). Resources also include quantities of oil and gas that are estimated, on a given date, to be potentially recoverable from known accumulations and undiscovered accumulations, that are not proved or probable reserves. Resources are a higher risk and are generally believed to be less likely to be recovered than proved and probable reserves. Total resources include synthetic crude oil estimates for both mining leases and for in-situ oil sands leases. Information on probable reserves and resources included in Management's Discussion and Analysis are reported in accordance with Canadian disclosure requirements. U.S. companies are prohibited in filings with the United States Securities and Exchange Commission from disclosing estimates of probable reserves and resources for non-mining properties. As a result, Suncor's reserve estimates may not be comparable to those made by U.S. companies.

Voyageur

In late 2001, Suncor issued a public disclosure document for the Voyageur growth strategy, which targets increasing production to 500,000 to 550,000 bpd in 2010 to 2012. When Suncor originally announced plans, the company stated it would apply for regulatory approval in late 2002.

Following initial stakeholder consultation and preliminary engineering, Suncor modified its Voyageur plan, deferring applications for regulatory approval until further details about each project phase are known and can be more fully discussed with stakeholders. Although the timing of Suncor's regulatory approval strategy has changed, the company's goal of increasing production capacity to 500,000 to 550,000 bpd in 2010 to 2012 remains the same.

Cost estimates for the Voyageur growth strategy will be provided once preliminary engineering is completed for each phase. Ultimate development of the Voyageur growth project requires approval of regulators and Suncor's Board of Directors.

Risk/Success Factors Affecting Performance

Management believes the strategic advantages of Oil Sands growth include:

- Economies of scale associated with higher levels of production from the existing Oil Sands infrastructure.
- Parallel processing in the extraction and upgrading processes that provides flexibility to schedule periodic plant maintenance while continuing to generate production from the remaining units.
- Access to nearly 13 billion barrels of bitumen resources with the potential to generate production growth without the level of exploration risk associated with conventional oil and gas operations.

Certain issues Suncor must manage that may affect performance include, but are not limited to the following:

- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to Corporate Overview, Liquidity and Capital Resources on page 25.
- The ability to complete future Oil Sands growth projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for skilled people, increased demands on the Fort McMurray, Alberta infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the Oil Sands plant. Suncor continues to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and developing internal core competency in engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Suncor believes it can reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering customized blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices and exchange factors and the light/heavy and sweet/sour crude oil differentials. Prices and differentials are difficult to predict and impossible to control.
- Unplanned production or operational outages and slowdowns. Outages can impact both production levels and costs.
- Suncor's relationship with its trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects. Suncor's current collective agreement with the Communications, Energy and Paperworkers Union, Local 707 expires May 1, 2004.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 38 under "Forward-looking Statement." Also refer to Corporate Overview, Risk/Success Factors Affecting Performance on page 23.

Natural Gas Overview

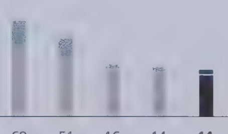
Suncor's Natural Gas business (NG) produces conventional natural gas in Western Canada and is exploring potential opportunities for coal bed methane production in North America. NG's production provides a price hedge for the natural gas consumed internally within Suncor's oil sands operations and downstream refinery.

In 2002, NG continued to advance its four-point strategy for profitable growth:

- Focusing on natural gas production to keep pace with growing projected internal consumption to maintain a **price hedge**.
- Building competitive operating areas.
- Improving base business efficiency.
- Creating new, low-capital business opportunities.

NG's 2002 average natural gas and liquids production volume of 33,700 barrels of oil equivalent per day (boe/d) was comparable to the 2001 average of 33,400 boe/d. Volume additions from new production in NG's core Western Canada operating areas were partially offset by natural reservoir declines in existing wells. Natural gas volumes as a percentage of total NG production remained constant at 88% in 2002 and 2001.

Total Proved Reserves
(millions of barrels of oil equivalent)



	98	99	00	01	02
Liquids	69	51	16	14	**14**
Natural gas	200	168	133	125	**118**
Total	269	219	149	139	**132**

NG activities have continued to be directed towards developing non-producing reserves.

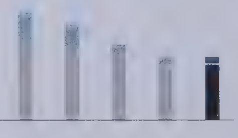
Summary of Results

Year ended December 31

($ millions unless otherwise noted)	**2002**	2001	2000
Revenue	**315**	458	428
Production (thousands boe/d)	**33.7**	33.4	40.5
Natural gas (mmcf/day)	**179**	177	200
Natural gas liquids (thousands bpd)	**2.4**	2.4	3.0
Crude oil (thousands bpd)	**1.5**	1.5	4.2
Average sales price			
Natural gas ($/thousand cubic feet)	**3.91**	6.09	4.72
Natural gas liquids ($/barrel)	**29.35**	34.38	36.66
Crude oil ($/barrel)	**31.72**	33.92	29.50
Net earnings	**35**	117	98
Cash flow provided from operations	**164**	280	238
Total assets	**765**	722	762
Investing activities	**158**	113	(186)
ROCE (%)	**9.2**	32.1	17.2

Natural gas converts to barrels of oil equivalent (boe) at a 6:1 ratio (six thousand cubic feet of natural gas:barrel of oil)

Production
(thousands of boe per day)



	98	99	00	01	02
Natural gas liquids and crude oil	16.3	13.4	7.2	3.9	**3.9**
Natural gas	41.2	37.7	33.3	29.5	**29.8**
Total	57.5	51.1	40.5	33.4	**33.7**

price hedge
Suncor-generated natural gas production that exceeds internal consumption provides the company a degree of protection from volatile market prices. In 2002, Suncor produced 179 million cubic feet per day (mmcf/d) of natural gas compared to consumption of approximately 110 mmcf/d.

Analysis of Net Earnings

NG's net earnings decreased to $35 million in 2002, from $117 million in 2001. The decrease was primarily due to lower natural gas prices, increased expenses and a higher effective income tax rate in 2002 compared to 2001, partially offset by lower royalty expenses. The 2001 effective tax rate was lower due to the positive earnings impact of enacted provincial rate reductions in 2001 applied to NG's future income tax liabilities.

Pricing

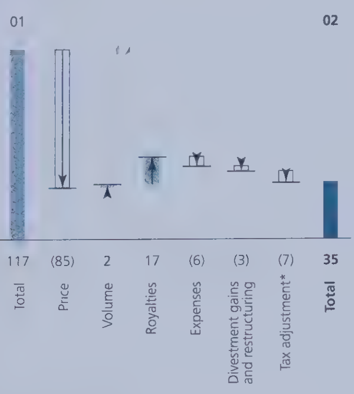
In 2002, NG's average price realized for natural gas was $3.91 per thousand cubic feet (mcf), 36% lower than the average $6.09 per mcf realized in 2001. High industry inventory levels at the beginning of 2002 and weaker industrial demand due to economic recession in the United States contributed to lower prices during the year. Prices for crude oil, which accounts for about 5% of NG production, were marginally lower at $31.72 per barrel (including hedging losses), compared to $33.92 per barrel (including hedging losses) in 2001. Natural gas liquids, accounting for the remaining 7% of production, averaged $29.35 per barrel in 2002, compared to $34.38 per barrel in 2001. The combined impact of the above pricing factors decreased earnings by $85 million compared to 2001.

Suncor NG Pricing vs. Industry Average
(Can$/thousand cubic feet)

	98	99	00	01	**02**
● Suncor NG average annual price	1.95	2.44	4.72	6.09	**3.91**
● Industry average reference price	1.95	2.47	4.53	5.40	**3.92**

The 2002 industry average reference price is an estimate.

Bridge Analysis of Net Earnings
(Cdn$ millions)



In 2002, lower natural gas prices, higher expenses and the absence of a 2001 tax adjustment were partially offset by lower royalties.

*Provincial income tax rate adjustment on opening future tax balances.

Total Expenses

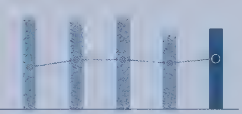
Royalties on NG production decreased to $65 million ($5.27 per boe) in 2002, from $104 million ($8.56 per boe) in 2001, reflecting lower average commodity prices. Lower royalties had a positive impact on earnings of $17 million for 2002.

Total expenses, excluding royalties, restructuring costs and divestment gains, increased to $179 million in 2002 from $168 million in 2001. Natural gas purchases were $7 million higher reflecting increased purchases made by NG on behalf of Suncor's Sarnia refinery. Operating expenses increased to $69 million in 2002 from $64 million in 2001 due to increased maintenance and higher costs related to employee benefits. Non-cash depreciation, depletion and amortization expenses of $75 million in 2002 increased by $5 million as a result of higher depletion rates. Offsetting these items were exploration expenses, which decreased by $5 million in 2002 due to lower seismic expenditures as a result of reduced exploration activities. The combined impact of the above expense items decreased earnings by $6 million compared to 2001.

Net Cash Surplus Analysis

NG had a net cash surplus of $28 million in 2002, compared to a net cash surplus of $211 million in 2001. Cash flow provided from operations decreased to

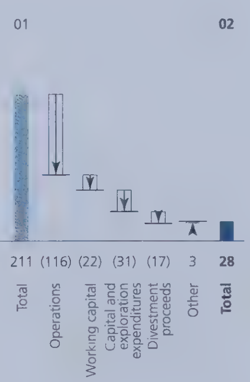
Lifting and Administration Costs



	98	99	00	01	**02**
■ Administration (Cdn$ millions)	29	28	29	24	**26**
● Lifting ($ per boe)	2.79	3.10	3.11	2.96	**3.15**

Total operating costs increased in 2002 due to increased maintenance and employee future benefit costs.

Bridge Analysis of Net Cash Surplus
(Cdn$ millions)



NG's cash surplus declined by $183 million in 2002. Lower natural gas prices and higher expenses reduced cash flow from operations. Higher capital expenditures for development drilling combined with lower proceeds from asset disposals further reduced the cash surplus.

$164 million in 2002, from $280 million in 2001 primarily as a result of lower prices and higher expenses, partially offset by lower royalty payments. Working capital decreased by $22 million in 2002, compared to a decrease of $44 million in 2001, due to a reduction in accounts receivable. Investing activities increased to $158 million in 2002, compared to $113 million in 2001. The $45 million increase reflects increased development drilling in existing focus areas, partially offset by lower divestment proceeds.

Outlook

NG's long-term goal is to achieve a sustainable return on capital employed of a minimum of 12% at mid-cycle natural gas prices (US$3.00 to US$3.50/mcf). To meet this target, management plans to increase production and continue work to improve base business efficiency, with a focus on reducing operating costs and capturing supply chain management benefits.

NG's long-term strategy is to increase production to exceed growing internal natural gas demands at the company's other integrated businesses. Internal demand in the latter half of 2003 is expected to grow to approximately 120 mmcf/d from 110 mmcf/d in 2002 in response to steam requirements for the Firebag In-situ Oil Sands Project. Internal demand is expected to continue to increase as subsequent stages of the Firebag Project begin production.

Suncor has budgeted $160 million in capital spending to support NG's 2003 production target of 185 to 190 mmcf/d of natural gas and approximately 3,300 barrels per day of liquids. The company plans to continue to leverage its expertise and existing assets to bring established reserves into production in western Alberta and northeastern British Columbia. However, increasing production will likely require expansion through industry arrangements such as **farm-ins**, joint ventures and acquisitions, which could expand the size and number of operating areas.

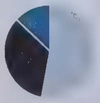
Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the NG business include, but are not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically. Positive or negative reserve revisions arising from technical and economic factors can have a corresponding positive or negative impact on asset valuation and depletion rates.
- The impact of market demand for land and services on capital and operating cost. Market demand and the availability of opportunities also influences the cost of acquisitions and the willingness of competitors to farm-out prospects.
- Risks and uncertainties associated with obtaining regulatory approval for exploration and development activities. These risks could add to costs or cause delays to projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 38 under "Forward-looking Statement." Also refer to the Corporate Overview, Risk/Success Factors Affecting Performance on page 23.

2002 System Proprietary Gas
(31% of sales)



	(mmcf/d)	(%)
TransCanada Gas Services	30	53
Pan Alberta	19	34
Other	7	13
Total	56	100

2002 Direct Proprietary Gas Sales
(69% of sales)

	(mmcf/d)	(%)
Alberta	53	43
British Columbia	14	11
Midwest U.S.	14	11
Eastern Canada	9	8
California	33	27
Total	123	100

farm-ins

Acquisitions of all or part of the operating rights from the working interest owner. The acquirer assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty but may retain any type of interest.

Energy Marketing and Refining Overview

Suncor's Energy Marketing and Refining (EM&R) business markets the company's refined products to industrial, wholesale and commercial customers principally in Ontario and Quebec, and to retail customers in Ontario through Sunoco-branded and joint venture operated retail networks. EM&R operates Suncor's refinery in Sarnia, Ontario, which has capacity to process 70,000 barrels per day of crude oil into gasolines, distillates and petrochemicals.

EM&R's downstream strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability and product yields and enhancing operational flexibility to process a variety of feedstock.
- Increasing the profitability and efficiency of retail networks by improving average site throughput and growing non-fuel ancillary retail revenue.
- Creating downstream integration opportunities to capture greater long-term value from Oil Sands production.

EM&R's retail networks in Ontario provide marketing channels for the company's refined products, accounting for approximately 62% of EM&R's total 2002 sales volumes of 91,100 barrels per day (bpd). EM&R's retail networks include 287 Sunoco-branded retail service stations, 18 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture[1] businesses comprising 148 Pioneer retail service stations, 50 UPI retail service stations and 15 UPI bulk distribution facilities for rural and farm fuels.

Wholesale and industrial gasoline and distillates sales were approximately 33% of EM&R's refined product sales in 2002. The remaining 5% was comprised of petrochemicals sold through Sun Petrochemicals Company, a 50% joint venture between a Suncor subsidiary and a U.S. based company.

[1] Pioneer Group Inc. is an independent company with which Suncor has a 50% joint venture partnership. UPI Inc. is a 50% joint venture company with GROWMARK Inc., a Midwest U.S. retail farm-supply and grain marketing co-operative.

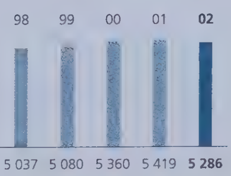
Prior to April 2002, EM&R also marketed natural gas to approximately 125,000 commercial and residential customers in Ontario. EM&R divested its Ontario retail natural gas marketing business during the second quarter of 2002 in order to focus on its core refined products business.

Summary of Results

Year ended December 31

($ millions unless otherwise noted)	**2002**	2001	2000
Revenue	**2 361**	2 588	2 604
Refined product sales (thousands of cubic metres)			
Sunoco retail gasoline	**1 642**	1 575	1 539
Total	**5 286**	5 419	5 360
Net earnings (loss) breakdown:			
Rack Back	**10**	47	69
Rack Forward	**16**	23	(1)
Gain on sale of retail natural gas marketing business	**35**	—	—
Tax adjustments	**—**	10	13
Total net earnings	**61**	80	81
Cash flow provided from operations	**107**	165	174
Investing activities	**34**	71	59
Net cash surplus	**63**	111	155
ROCE (%)	**12.5**	18.4	20.5

Refined Product Sales Volume
(thousands of cubic metres)



Total sales volume decreased by 2% over 2001 due mainly to lower distillate sales driven by lower demand and the non-renewal of jet fuel contracts.

Analysis of Net Earnings

EM&R's 2002 net earnings were $61 million, compared with $80 million in 2001. Excluding the net earnings effects of the gain on the sale of the retail natural gas marketing business, net earnings were $26 million in 2002, compared to $80 million in 2001. This decrease was primarily due to reduced refining margins and higher cash operating costs, partially offset by the benefits of higher refinery crude utilization. Net earnings in 2002 were also lower compared to 2001 as 2001 earnings included the positive impact of a tax rate reduction on EM&R's future income tax liabilities.

Rack Back

Net earnings for **Rack Back** were $10 million in 2002, compared with $47 million in 2001, including the impact of a $9 million gain on liquidation of excess natural gas supplies in 2001. The decrease was primarily due to lower refining margins and higher operating expenses, partially offset by improved refinery yield.

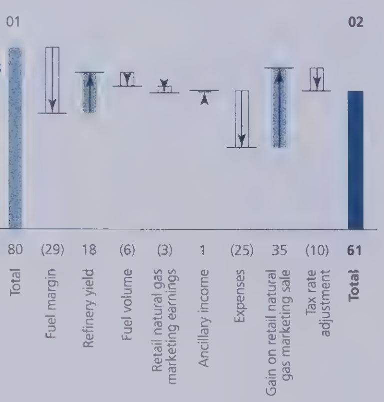
Refining margins decreased 16% to 4.8 cents per litre (cpl) in 2002, compared to 5.7 cpl in 2001, reflecting weak gasoline and distillates margins across North America. Lower margins reduced earnings for 2002 by $32 million, more than offsetting an $18 million improvement in earnings due to higher refinery yield and lower product purchase costs.

Rack Back sales volumes (including volumes sold to the Rack Forward business) averaged 14,500 cubic metres per day (91,100 bpd), down from 14,800 cubic metres per day (93,400 bpd) in 2001. Reduced sales volumes reflect the non-renewal of jet fuel contracts and lower distillate sales driven by weakened demand, partially offset by higher gasoline and petrochemical sales volumes. This resulted in a decline in Rack Back earnings of $3 million compared to 2001. EM&R's refined product market share in its primary market of Ontario declined to 17% in 2002, compared to 18% in 2001. Approximately 86% of EM&R's refined products were sold to the Ontario market in 2002.

In addition to a 34-day planned maintenance shutdown on a portion of the refinery's operations in the second quarter, there were a number of unplanned outages in 2002 that affected plant availability. Following planned and unplanned maintenance work, all units returned to normal performance level with an improved crude utilization rate of 100% and 108% in the last two quarters of 2002, respectively. Overall, the refinery's crude utilization averaged 95% in 2002, compared to 92% in 2001. Despite additional product purchases that were made to satisfy customer demand during the planned and unplanned periods of lower production, total product purchases made in 2002 were lower compared to 2001 due to the improvement in refinery reliability.

Rack Back's after-tax expenses were $20 million higher in 2002 compared to 2001, due in part to higher employee future benefits of $4 million, higher electricity costs of $3 million due to deregulation of the Ontario electricity market and increased maintenance and other general and administrative expenses. Expenses were also higher in 2002 compared to 2001 as 2001 results included a $9 million gain on liquidation of excess natural gas supplies.

Bridge Analysis of Earnings
(Cdn$ millions)



Reduced downstream margins, lower fuel sales volumes and higher expenses were partially offset by improved refinery yield and a gain on the sale of the retail natural gas marketing business. No tax adjustment was recorded in 2002.

Margins
(Cdn cents per litre)

	98	99	00	01	**02**
● Retail gasoline margin	7.0	7.4	6.6	6.6	**6.6**
● Refining margin	4.1	4.0	5.9	5.7	**4.8**

The refining margin declined 16% from 2001 in response to weakened demand and high inventory levels in North America. Retail gasoline margin remained stable relative to 2001.

Rack Back and Rack Forward

EM&R's financial reporting is based on its Rack Back/Rack Forward organizational structure. The Rack Back division includes the procurement and refining of crude oil and feedstock, and sales and distribution to the Sarnia refinery's largest industrial and reseller customers. Rack Forward includes retail operations, cardlock and industrial/commercial sales, and the UPI and Pioneer joint venture businesses.

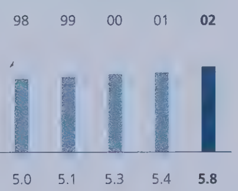
Rack Forward

Rack Forward net earnings for 2002 increased to $51 million, compared to $23 million in 2001. Excluding the net earnings effect of a $35 million gain on the sale of the retail natural gas marketing business, Rack Forward net earnings decreased to $16 million compared to $23 million in 2001. The decrease was primarily attributable to lower earnings from the commercial and reseller sales channels and higher employee future benefits costs, which were partially offset by improved retail gasoline volumes. Also impacting Rack Forward's results was a $3 million reduction in retail natural gas marketing earnings over 2001. This business was sold at the beginning of the second quarter of 2002.

Gasoline sales volumes in the Sunoco-branded retail network grew by more than 4% in 2002 despite the closure of 19 sites, contributing to an earnings improvement of $2 million. Average site throughput was 5.8 million litres per site in 2002, a 7% improvement from the 5.4 million litres per site in 2001, reflecting continued improvement in network efficiency. EM&R's Ontario retail gasoline market share, including all Sunoco and joint venture operated retail sites, remained constant at 20%. EM&R's Sunoco-branded retail gasoline margin averaged 6.6 cpl, unchanged from 2001.

Royalty and **ancillary income** was $1 million higher than 2001, reflecting continued expansion of non-fuel products and services in the retail network. Due to aggressive price competition and commodity price volatility throughout 2002, earnings from the commercial and reseller sales channels declined by $2 million.

Sunoco-branded Retail Network Throughput
(millions of litres per site)



Throughput per site – Millions of litres per site based on the average number of sites.

Rack Forward expenses were $5 million higher compared to 2001 primarily due to higher employee future benefits and higher marketing costs.

Net earnings from the retail joint ventures with Pioneer and UPI totalled $5 million in 2002, unchanged from 2001.

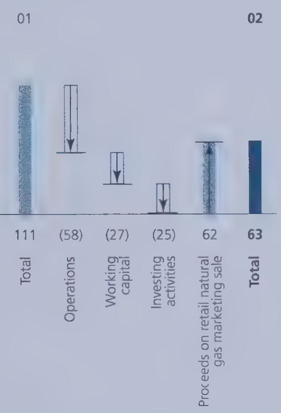
Net Cash Surplus Analysis

Cash flow from operations decreased to $107 million in 2002 from $165 million in 2001 as a result of lower earnings as described above. Working capital increased by $10 million in 2002, compared to a decline of $17 million in 2001 reflecting the impact of the sale of the retail natural gas marketing business and a net increase in trade receivables reflecting higher commodity prices.

Cash used in investing activities was $34 million in 2002, compared to $71 million in 2001. Higher capital spending and deferred maintenance costs in 2002 were more than offset by the $62 million net proceeds from the sale of the retail natural gas marketing business. Investing activities in 2002 also included $18 million for the planned maintenance shutdown at the Sarnia refinery, compared to $9 million in 2001.

The impact of these factors decreased the 2002 net cash surplus to $63 million, compared to $111 million in 2001.

Bridge Analysis of Net Cash Surplus
(Cdn$ millions)



Net cash surplus declined by $48 million in 2002. Lower earnings led to reduced cash flow from operations. Increased working capital requirements and capital expenditures further reduced the net cash surplus. These reductions were partially offset by proceeds from the sale of the retail natural gas marketing business.

ancillary income
Income earned from non-fuel products and services such as car washes, sale of fast foods and confectionery items.

Outlook

To enhance competitiveness and to position the Sunoco-branded retail network for growth, EM&R plans to develop new Sunoco retail sites, upgrade existing facilities and close down low-volume, under-performing retail assets. EM&R will also target increased fuel and non-fuel revenue by focusing marketing initiatives on premium petroleum and ancillary offerings.

To further integrate the company's upstream and downstream businesses, EM&R continues to assess new marketing and refining investment opportunities to capture the greatest long term value from Suncor's Oil Sands production.

Regulation regarding low-sulphur gasoline specifications prescribes limits for sulphur levels in gasoline to an average of 150 parts per million (ppm) from mid-2002 to the end of 2004, and a maximum of 30 ppm by 2005. To meet these specifications, EM&R is constructing a desulphurization unit at the Sarnia refinery at an estimated cost of $40 million. The project is expected to be completed in 2003, more than a year ahead of the legislated deadline.

In 2002, the Canadian government passed legislation limiting the concentration of sulphur in diesel fuel produced or imported for use in on-road vehicles. The legislation places a limit on sulphur levels of 500 ppm until May 31, 2006 and a maximum of 15 ppm thereafter. Capital spending required by EM&R for compliance is estimated to be approximately $225 million from 2003 through 2005.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the EM&R business include, but are not limited to, the following:

- While EM&R's margins improved in the second half of 2002, management expects fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants, will continue to impact the business environment.
- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel and light fuel oil to take effect later in the decade. Capital spending required is subject to the development of such regulations and strategic assessment. Several strategic options are being evaluated by EM&R to enhance integration with Oil Sands and increase value through integration with the diesel desulphurization facilities.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed below. Also refer to the Corporate Overview, Risk/Success Factors Affecting Performance on page 23.

Forward-looking Statement

This Management's Discussion and Analysis contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules and production volumes, operating and financial results, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "plans," "intends," "believes," "projects," "indicates," "could," "vision," "goal," "target," "objective" and similar expressions. These statements are not guarantees of future performance and involve a number of risks, uncertainties and assumptions. Suncor's business is subject to risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

The risks, uncertainties and other factors that could influence actual results include: changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; fluctuations in commodity prices; fluctuations in currency exchange rates; Suncor's ability to respond to changing markets; the ability of Suncor to receive timely regulatory approvals; the successful implementation of its growth projects including the Firebag In-situ Oil Sands Project and Voyageur; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of Suncor's production estimates and production levels and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; actions by governmental authorities including increasing taxes, government fees, changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form/Form 40-F on file with the Alberta Securities Commission and certain other securities regulatory authorities. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 41 to 73 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

We, as Suncor's Chief Executive Officer and Chief Financial Officer, will certify Suncor's annual disclosure document filed with the United States Securities and Exchange Commission (Form 40-F) as required by the new United States Sarbanes-Oxley Act.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 41 to 44. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of all aspects of the company's operations.

In order to provide their opinion on the accompanying consolidated financial statements, PricewaterhouseCoopers LLP, the independent external auditors, review the company's system of internal controls and conduct their work to the extent that they consider appropriate. The company also retains independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd. to conduct independent evaluations or audits of the company's oil and gas reserves.

The Audit Committee of the Board of Directors, composed of five independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and the internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. On an annual basis, the Audit Committee meets with the independent petroleum consultants and reviews the company's annual reserve estimates. The Audit Committee meets quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements, Management's Discussion and Analysis and Annual Information Form/Form 40-F, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.

Rick George

S. W. Williams

Rick George
President and
Chief Executive Officer

Steve Williams
Executive Vice President, Corporate Development
and Chief Financial Officer

January 17, 2003

AUDITORS' REPORT

To the Shareholders of Suncor Energy Inc.

We have audited the consolidated balance sheets of Suncor Energy Inc. as at December 31, 2002 and 2001 and the consolidated statements of earnings, cash flows and changes in shareholders' equity for each of the years in the three year period ended December 31, 2002. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

January 17, 2003

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's financial statements, such as the change described in note 1 to the consolidated financial statements. Our report to the shareholders dated January 17, 2003 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

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SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Suncor Energy Inc. is an integrated Canadian energy company, comprised of three operating segments: Oil Sands, Natural Gas and Energy Marketing and Refining.

Oil Sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands mined in the Athabasca region of northeastern Alberta, and the marketing of these products in Canada and the United States.

Natural Gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas and crude oil in Canada and the United States.

Energy Marketing and Refining includes the manufacture, transportation and marketing of petroleum and petrochemical products, primarily in Ontario and Quebec. Petrochemical products are also sold in the United States and Europe.

The significant accounting policies of the company are summarized below:

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. These differences are quantified and explained in note 19.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint ventures.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Cash Equivalents and Investments

Cash equivalents consist primarily of term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less. Investments with maturities greater than three months to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues

Crude oil sales from upstream operations (Oil Sands and Natural Gas) to downstream operations (Energy Marketing and Refining) are based on actual product shipments. On consolidation, revenues and purchases related to these sales transactions are eliminated from operating revenues and purchases of crude oil and products.

The company also uses a portion of its natural gas production for internal consumption at its oil sands plant and Sarnia refinery. On consolidation, revenues from these sales are eliminated from operating revenues, crude oil and products purchases, and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer and delivery has taken place. Revenues from oil and natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest.

(d) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

Expenditures to acquire and develop Oil Sands mining properties, and net costs relating to production during the development phase, are capitalized. Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are also capitalized.

The company follows the successful efforts method of accounting for its conventional and in-situ oil sands crude oil operations and its natural gas operations. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are initially capitalized. If it is determined that the well does not contain proved reserves, the capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. Related land costs are expensed through the amortization of unproved properties as covered under the Natural Gas section of the depreciation, depletion and amortization policy on page 42.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Costs incurred at the inception of operations are expensed.

Interest Capitalization

Interest costs relating to major capital projects in progress and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use.

Leases

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Gains and losses on the sale and leaseback of assets recorded as capital leases are deferred and amortized to earnings in proportion to the amortization of leased assets.

Depreciation, Depletion and Amortization

OIL SANDS Property, plant and equipment are depreciated over their useful lives on a straight-line basis, commencing when the assets are placed into service. Mine and mobile equipment is depreciated over periods ranging from three to 20 years and plant and other property and equipment, including leases in service, primarily over four to 40 years. Capitalized costs related to the in-progress phase of projects are not depreciated until the facilities are substantially complete and ready for commercial production to commence.

NATURAL GAS Acquisition costs of unproved properties that are individually significant are evaluated for impairment by management. Impairment of unproved properties that are not individually significant is provided for through amortization over the average projected holding period for that portion of acquisition costs not expected to become producing, based on historical experience.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight-line basis over their useful lives, which average 12 years.

ENERGY MARKETING AND REFINING Depreciation of property, plant and equipment is provided for on a straight-line basis over their useful lives. The refinery and additions are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and other facilities and equipment over three to 25 years.

Reclamation and Environmental Remediation Costs

Reclamation and environmental remediation costs for identified sites are estimated and charged against earnings when a regulatory or statutory requirement or contractual agreement exists, or when management has made a decision to decommission or restore a site, providing that assessments indicate that such costs are probable and reasonably estimable.

Estimated reclamation costs in the company's upstream operations are accrued on the unit of production basis. Estimated environmental remediation costs, which are predominantly in the company's downstream operations, are accrued during the period for those sites where assessments indicate that such work is required.

Costs are accrued based upon currently known information, estimated timing of remedial actions, and existing regulatory requirements and technology. Changes in these factors may result in material changes to estimated costs, which will be recognized prospectively when known.

Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less related provisions for reclamation and environmental remediation costs and future income taxes, may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the estimated net recoverable amount is recognized during the period, with a charge to earnings.

Disposals

Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, gains or losses are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of an unproved property surrendered or abandoned that is not individually significant, or a partial abandonment of a proved property, is charged to accumulated depreciation, depletion or amortization.

(e) Deferred Charges and Other

Overburden removal may precede mining of the oil sands deposit by as much as two years. In order to match expense with the oil sands mined in the year, the company employs a deferral method of accounting for overburden removal costs where all such costs are initially recorded as a deferred charge (see note 3), rather than expensing overburden removal costs as incurred. These deferred charges are allocated to the mining activity in the year on a last-in, first-out (LIFO) basis using a life-of-mine stripping ratio for each mine pit whereby all of the overburden to be removed is related to all of the oil sands proved and probable ore reserves. This expense is reported as part of the depreciation, depletion and amortization expense in the consolidated statements of earnings. Stripping ratios are regularly reviewed to reflect changes in operating experience and other factors.

The cost of major maintenance shutdowns is deferred and amortized on a straight-line basis over the period to the next shutdown, which varies from three to seven years. Normal maintenance and repair costs are charged to expense as incurred.

(f) Employee Future Benefits

The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued ratably from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based upon a year-end market rate of interest. Company contributions to the defined contribution plan are expensed as incurred.

(g) Inventories

Inventories of crude oil and refined products are valued at the lower of cost using the LIFO method and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value.

(h) Derivative Financial Instruments

The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of market prices for its petroleum and natural gas products and to manage the exposure to fluctuations in its Canadian dollar earnings and cash flows due to adverse foreign currency exchange movements. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage exposure to interest rate fluctuations.

These derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the consolidated balance sheets. Gains or losses on these contracts, including realized gains and losses on hedging derivative contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized. Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Commencing in the fourth quarter of 2002, the company began to use energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. Trading activities are accounted for at fair value.

(i) Foreign Currency Translation

Monetary assets and liabilities in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. Other assets and related depreciation, depletion and amortization, other liabilities, and revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

(j) Stock-based Compensation Plans

Under the company's common share option programs (see note 11), common share options are granted to executives, employees and non-employee directors. Compensation expense is not recognized at the initial grant of the common share options and consideration paid to the company on exercise of stock options is credited to share capital.

Stock-based compensation awards that are to be settled in cash are measured using the fair value based method of accounting.

(k) Recently Issued Accounting Standards

Hedging Relationships

Canadian Accounting Guideline 13 (AcG 13) "Hedging Relationships" is applicable to the company's hedging relationships in 2004 and subsequent fiscal years. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, as well as the discontinuance of hedge accounting. The Guideline does not specify hedge accounting methods. The company is evaluating the impact of implementing the standard.

Asset Retirement Obligations

A new Canadian standard "Asset Retirement Obligations" (ARO) substantially harmonizes Canadian GAAP with U.S. GAAP (see note 19). The standard requires that a liability associated with the retirement of property, plant and equipment be recognized when incurred. The liability would be measured initially at fair value and the resulting costs capitalized. Capitalized costs would be amortized according to normal amortization practices. Subsequent to initial recognition the ARO liability would be adjusted for the accretion of discount and changes in the amount or timing of the underlying future cash flows. The standard is effective no later than January 1, 2004. The company is evaluating the impact of implementing the standard.

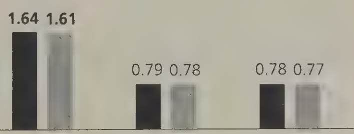
CONSOLIDATED STATEMENTS OF EARNINGS

for the years ended December 31

($ millions)	2002	2001	2000
REVENUES			
Operating revenues (notes 5, 15, 17 and 18)	**4 902**	4 194	3 385
Interest	**2**	5	3
	4 904	4 199	3 388
EXPENSES			
Purchases of crude oil and products (note 15)	**1 298**	1 595	807
Operating, selling and general	**1 292**	1 012	918
Depreciation, depletion and amortization	**585**	360	365
Exploration (note 18)	**26**	22	53
Royalties	**98**	134	199
Taxes other than income taxes (note 18)	**374**	367	361
(Gain) on disposal of assets	**(2)**	(7)	(148)
(Gain) on sale of retail natural gas marketing business (note 16)	**(38)**	—	—
Project start-up costs	**3**	141	15
Write-off of oil shale assets	—	48	125
Restructuring (note 18)	—	(2)	65
Financing expenses (note 13)	**124**	16	8
	3 760	3 686	2 768
EARNINGS BEFORE INCOME TAXES	**1 144**	513	620
Provision for income taxes (note 8)			
Current	**74**	4	45
Future	**309**	121	198
	383	125	243
NET EARNINGS	**761**	388	377
Dividends on preferred securities, net of tax (note 10)	**(28)**	(26)	(26)
Revaluation of US$ preferred securities, net of tax (note 1)	**1**	(11)	(6)
Net earnings attributable to common shareholders	**734**	351	345

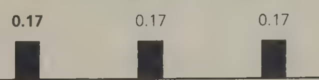
PER COMMON SHARE (dollars) (note 12)

Net earnings attributable to common shareholders



■ basic
● diluted

Cash dividends



See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS

as at December 31

($ millions)	**2002**	2001
ASSETS		
Current assets		
Cash and cash equivalents	**15**	1
Accounts receivable (notes 9(c) and 17)	**403**	306
Inventories (note 14)	**266**	258
Income taxes recoverable	**—**	28
Future income taxes (note 8)	**38**	29
Total current assets	**722**	622
Property, plant and equipment, net (note 2)	**7 641**	7 141
Deferred charges and other (note 3)	**185**	199
Future income taxes (note 8)	**135**	132
Total assets	**8 683**	8 094
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt	**—**	31
Accounts payable and accrued liabilities (notes 6 and 7)	**716**	672
Income taxes payable	**34**	—
Taxes other than income taxes	**37**	42
Future income taxes (note 8)	**10**	28
Total current liabilities	**797**	773
Long-term debt (note 4)	**2 686**	3 113
Accrued liabilities and other (notes 6 and 7)	**226**	251
Future income taxes (note 8)	**1 516**	1 177
Total liabilities	**5 225**	5 314
Commitments and contingencies (note 9)		
Shareholders' equity		
Preferred securities (note 10)	**523**	525
Share capital (note 11)	**578**	555
Retained earnings	**2 357**	1 700
Total shareholders' equity	**3 458**	2 780
Total liabilities and shareholders' equity	**8 683**	8 094

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board:

Rick George

Rick George
Director

Robert Korthals

Robert Korthals
Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended December 31

($ millions)	2002	2001	2000
OPERATING ACTIVITIES			
Cash flow provided from operations[a]	**1 440**	831	958
Decrease (increase) in operating working capital			
Accounts receivable	**(97)**	101	(130)
Inventories	**(8)**	(66)	(31)
Accounts payable and accrued liabilities	**44**	(37)	93
Taxes payable	**77**	(17)	18
Cash provided from operating activities	**1 456**	812	908
CASH USED IN INVESTING ACTIVITIES[a]	**(861)**	(1 680)	(1 607)
NET CASH SURPLUS (DEFICIENCY) BEFORE FINANCING ACTIVITIES	**595**	(868)	(699)
FINANCING ACTIVITIES			
Increase (decrease) in short-term debt	**(31)**	(33)	32
Proceeds from issuance of long-term debt	**797**	500	—
Net increase (decrease) in other long-term debt	**(1 245)**	486	792
Issuance of common shares under stock option plans	**19**	15	9
Dividends paid on preferred securities	**(48)**	(48)	(47)
Dividends paid on common shares	**(73)**	(72)	(71)
Cash provided from (used in) financing activities	**(581)**	848	715
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**14**	(20)	16
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**1**	21	5
CASH AND CASH EQUIVALENTS AT END OF YEAR	**15**	1	21

(a) See Schedules of Segmented Data on pages 50 and 51.

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

for the years ended December 31

($ millions)	Preferred Securities	Share Capital	Retained Earnings
At December 31, 1999, as previously reported	514	524	1 070
Retroactive adjustment for change in accounting policy, net of tax (note 1)	(12)	—	9
At December 31, 1999, as restated	502	524	1 079
Net earnings	—	—	377
Dividends paid on preferred securities, net of tax	—	—	(26)
Dividends paid on common shares	—	—	(71)
Issued for cash under stock option plans	—	9	—
Issued under dividend reinvestment plan	—	4	(4)
Income taxes – impact of new standard	—	—	75
Revaluation of US$ preferred securities (note 1)	8	—	(6)
At December 31, 2000, as restated	510	537	1 424
Net earnings	—	—	388
Dividends paid on preferred securities, net of tax	—	—	(26)
Dividends paid on common shares	—	—	(72)
Issued for cash under stock option plans	—	15	—
Issued under dividend reinvestment plan	—	3	(3)
Revaluation of US$ preferred securities (note 1)	15	—	(11)
At December 31, 2001, as restated	**525**	**555**	**1 700**
Net earnings	—	—	**761**
Dividends paid on preferred securities, net of tax	—	—	**(28)**
Dividends paid on common shares	—	—	**(73)**
Issued for cash under stock option plans	—	**19**	—
Issued under dividend reinvestment plan	—	**4**	**(4)**
Revaluation of US$ preferred securities (note 1)	**(2)**	—	**1**
At December 31, 2002	**523**	**578**	**2 357**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA[a]

for the years ended December 31

	Oil Sands			Natural Gas			Energy Marketing and Refining		
($ millions)	**2002**	2001	2000	**2002**	2001	2000	**2002**	2001	2000
EARNINGS									
Revenues[b]									
Operating revenues	**2 284**	1 227	544	**255**	382	237	**2 361**	2 585	2 604
Intersegment revenues (note 15)[c]	**375**	158	792	**60**	76	191	**—**	3	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—
	2 659	1 385	1 336	**315**	458	428	**2 361**	2 588	2 604
Expenses									
Purchases of crude oil and products (note 15)	**149**	99	3	**16**	9	—	**1 564**	1 721	1 783
Operating, selling and general	**806**	481	467	**69**	64	74	**352**	350	310
Depreciation, depletion and amortization	**450**	233	232	**75**	70	78	**58**	56	54
Exploration	**9**	—	—	**17**	22	53	**—**	—	—
Royalties	**33**	30	98	**65**	104	101	**—**	—	—
Taxes other than income taxes	**23**	12	12	**2**	3	3	**348**	351	345
(Gain) loss on disposal of assets	**2**	1	—	**(4)**	(8)	(147)	**—**	—	(1)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**(38)**	—	—
Project start-up costs	**3**	141	15	**—**	—	—	**—**	—	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**—**	(2)	65	**—**	—	—
Financing expenses	**—**	—	—	**—**	—	—	**—**	—	—
	1 475	997	827	**240**	262	227	**2 284**	2 478	2 491
Earnings (loss) before income taxes	**1 184**	388	509	**75**	196	201	**77**	110	113
Provision for income taxes	**(391)**	(105)	(194)	**(40)**	(79)	(103)	**(16)**	(30)	(32)
Net earnings (loss)	**793**	283	315	**35**	117	98	**61**	80	81
As at December 31									
TOTAL ASSETS	**6 896**	6 409	5 079	**765**	722	762	**968**	934	911
CAPITAL EMPLOYED[d]	**4 540**	1 398	1 412	**449**	317	412	**491**	483	386

(a) The company currently has no foreign geographic segments. See note 18 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

(b) One customer in the Oil Sands segment represented 10% or more ($641 million) of the company's 2002 consolidated revenues (2001 – one customer represented 10% or more ($450 million); 2000 – two customers represented 10% or more ($493 million and $355 million)).

(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

(d) Capital employed – the total of shareholders' equity and short-term and long-term debt, less capitalized costs related to major projects in progress.

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA[a] (continued)

for the years ended December 31

($ millions)	Corporate and Eliminations 2002	2001	2000	Total 2002	2001	2000
EARNINGS						
Revenues[b]						
Operating revenues	**2**	—	—	**4 902**	4 194	3 385
Intersegment revenues (note 15)[c]	**(435)**	(237)	(983)	**—**	—	—
Interest	**2**	5	3	**2**	5	3
	(431)	(232)	(980)	**4 904**	4 199	3 388
Expenses						
Purchases of crude oil and products (note 15)	**(431)**	(234)	(979)	**1 298**	1 595	807
Operating, selling and general	**65**	117	67	**1 292**	1 012	918
Depreciation, depletion and amortization	**2**	1	1	**585**	360	365
Exploration	**—**	—	—	**26**	22	53
Royalties	**—**	—	—	**98**	134	199
Taxes other than income taxes	**1**	1	1	**374**	367	361
(Gain) loss on disposal of assets	**—**	—	—	**(2)**	(7)	(148)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**(38)**	—	—
Project start-up costs	**—**	—	—	**3**	141	15
Write-off of oil shale assets	**—**	48	125	**—**	48	125
Restructuring	**—**	—	—	**—**	(2)	65
Financing expenses	**124**	16	8	**124**	16	8
	(239)	(51)	(777)	**3 760**	3 686	2 768
Earnings (loss) before income taxes	**(192)**	(181)	(203)	**1 144**	513	620
Provision for income taxes	**64**	89	86	**(383)**	(125)	(243)
Net earnings (loss)	**(128)**	(92)	(117)	**761**	388	377
As at December 31						
TOTAL ASSETS	**54**	29	81	**8 683**	8 094	6 833
CAPITAL EMPLOYED[d]	**154**	33	22	**5 634**	2 231	2 232

SCHEDULES OF SEGMENTED DATA[a] (continued)

for the years ended December 31

($ millions)	Oil Sands 2002	Oil Sands 2001	Oil Sands 2000	Natural Gas 2002	Natural Gas 2001	Natural Gas 2000	Energy Marketing and Refining 2002	Energy Marketing and Refining 2001	Energy Marketing and Refining 2000
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash provided from (used in) operating activities:									
Cash flow provided from (used in) operations									
Net earnings (loss)	**793**	283	315	**35**	117	98	**61**	80	81
Exploration expenses									
Cash	**—**	—	—	**6**	12	12	**—**	—	—
Dry hole costs	**—**	—	—	**11**	10	41	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**450**	233	232	**75**	70	78	**58**	56	54
Future income taxes	**379**	89	189	**37**	76	101	**(35)**	18	(16)
Current income tax provision allocated to Corporate	**12**	16	5	**3**	3	2	**51**	12	48
(Gain) loss on disposal of assets	**2**	1	—	**(4)**	(8)	(147)	**—**	—	(1)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**(38)**	—	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**—**	(3)	56	**—**	—	—
Other	**12**	(4)	(12)	**2**	3	(4)	**9**	2	6
Overburden removal outlays	**(160)**	(31)	(48)	**—**	—	—	**—**	—	—
Overburden removal outlays – Project Millennium (start-up period)	**—**	(88)	(27)	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**(8)**	(13)	1	**(1)**	—	1	**1**	(3)	2
Total cash flow provided from (used in) operations	**1 480**	486	655	**164**	280	238	**107**	165	174
Decrease (increase) in operating working capital	**(121)**	(35)	(169)	**22**	44	27	**(10)**	17	40
Total cash provided from (used in) operating activities	**1 359**	451	486	**186**	324	265	**97**	182	214
Cash provided from (used in) investing activities:									
Capital and exploration expenditures	**(617)**	(1 479)	(1 808)	**(163)**	(132)	(127)	**(60)**	(54)	(45)
Deferred maintenance shutdown expenditures	**(9)**	(5)	(3)	**—**	(2)	(1)	**(18)**	(9)	(9)
Deferred outlays and other investments	**(4)**	(2)	(5)	**—**	(1)	—	**(18)**	(9)	(7)
Proceeds from disposals	**—**	10	101	**5**	22	314	**62**	1	2
Total cash provided from (used in) investing activities	**(630)**	(1 476)	(1 715)	**(158)**	(113)	186	**(34)**	(71)	(59)
Net cash surplus (deficiency) before financing activities	**729**	(1 025)	(1 229)	**28**	211	451	**63**	111	155

(a) The company currently has no foreign geographic segments. See note 18 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA[a] (continued)

for the years ended December 31

($ millions)	Corporate and Eliminations 2002	2001	2000	Total 2002	2001	2000
CASH FLOW BEFORE FINANCING ACTIVITIES						
Cash provided from (used in) operating activities:						
Cash flow provided from (used in) operations						
Net earnings (loss)	**(128)**	(92)	(117)	**761**	388	377
Exploration expenses						
Cash	**—**	—	—	**6**	12	12
Dry hole costs	**—**	—	—	**11**	10	41
Non-cash items included in earnings						
Depreciation, depletion and amortization	**2**	1	1	**585**	360	365
Future income taxes	**(72)**	(62)	(76)	**309**	121	198
Current income tax provision allocated to Corporate	**(66)**	(31)	(55)	**—**	—	—
(Gain) loss on disposal of assets	**—**	—	—	**(2)**	(7)	(148)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**(38)**	—	—
Write-off of oil shale assets	**—**	48	125	**—**	48	125
Restructuring	**—**	—	—	**—**	(3)	56
Other	**(3)**	7	(7)	**20**	8	(17)
Overburden removal outlays	**—**	—	—	**(160)**	(31)	(48)
Overburden removal outlays – Project Millennium (start-up period)	**—**	—	—	**—**	(88)	(27)
Increase (decrease) in deferred credits and other	**(44)**	29	20	**(52)**	13	24
Total cash flow provided from (used in) operations	**(311)**	(100)	(109)	**1 440**	831	958
Decrease (increase) in operating working capital	**125**	(45)	52	**16**	(19)	(50)
Total cash provided from (used in) operating activities	**(186)**	(145)	(57)	**1 456**	812	908
Cash provided from (used in) investing activities:						
Capital and exploration expenditures	**(37)**	(13)	(18)	**(877)**	(1 678)	(1 998)
Deferred maintenance shutdown expenditures	**—**	—	—	**(27)**	(16)	(13)
Deferred outlays and other investments	**(2)**	(7)	(1)	**(24)**	(19)	(13)
Proceeds from disposals	**—**	—	—	**67**	33	417
Total cash provided from (used in) investing activities	**(39)**	(20)	(19)	**(861)**	(1 680)	(1 607)
Net cash surplus (deficiency) before financing activities	**(225)**	(165)	(76)	**595**	(868)	(699)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Change in Accounting Policy

Effective January 1, 2002, the company retroactively adopted the new Canadian accounting standard for Foreign Currency Translation, and as a result, all prior periods have been restated. This new standard applies to the company's foreign currency denominated long-term debt and preferred securities (see notes 4 and 10). The impact of this new standard on the consolidated balance sheets and statements of earnings is as follows:

Change in Consolidated Balance Sheets

($ millions, increase (decrease))	**2002**	2001
Future income taxes – long-term liabilities	**3**	(4)
Preferred securities	**(2)**	15
Retained earnings	**9**	(11)

Change in Consolidated Statements of Earnings

($ millions, increase (decrease))	**2002**	2001	2000
Financing expenses	**(10)**	—	—
Future income taxes	**2**	—	—
Net earnings	**8**	—	—
Revaluation of US$ preferred securities, net of tax	**1**	(11)	(6)
Net earnings attributable to common shareholders	**9**	(11)	(6)
Per common share – basic and diluted (dollars)	**$0.02**	($0.02)	($0.01)

2. Property, Plant and Equipment

($ millions)	**2002** Cost	**2002** Accumulated Provision	2001 Cost	2001 Accumulated Provision
Oil Sands				
Plant	**5 340**	**691**	1 744	557
Mine and mobile equipment	**1 154**	**381**	1 008	337
Pipeline costs	**81**	**26**	81	23
Capital leases	**121**	**12**	109	6
Major projects in progress				
Project Millennium	**—**	**—**	3 618	8
Firebag and other	**702**	**—**	275	—
	7 398	**1 110**	6 835	931
Natural Gas				
Proved properties	**1 053**	**480**	931	423
Unproved properties	**150**	**41**	148	48
Pipeline	**20**	**18**	20	17
Other support facilities and equipment	**16**	**11**	14	8
	1 239	**550**	1 113	496
Energy Marketing and Refining				
Refinery	**800**	**417**	771	391
Marketing and transportation	**461**	**229**	434	209
	1 261	**646**	1 205	600
Corporate	**55**	**6**	19	4
	9 953	**2 312**	9 172	2 031
Net property, plant and equipment		**7 641**		7 141

3. Deferred Charges and Other

($ millions)	2002	2001
Oil sands overburden removal costs (see below)	**68**	101
Deferred maintenance shutdown costs	**44**	34
Other	**73**	64
Total deferred charges and other	**185**	199
Oil sands overburden removal costs		
Balance – beginning of year	**101**	76
Outlays during the year	**160**	119
Depreciation on equipment during year	**9**	9
	270	204
Amortization during year	**(202)**	(103)
Balance – end of year	**68**	101

4. Long-term Debt

($ millions)	2002	2001
Fixed-term debt, redeemable at the option of the company		
7.15% Notes, denominated in U.S. dollars, due in 2032 [a]	**790**	—
6.70% Series 2 Medium Term Notes, due in 2011 [b]	**500**	500
6.80% Medium Term Notes, due in 2007 [b]	**250**	250
6.10% Medium Term Notes, due in 2007 [b]	**150**	150
7.40% Debentures, Series C, due in 2004	**125**	125
	1 815	1 025
Revolving-term debt, with interest at variable rates (see Credit Facilities)		
Commercial Paper, interest at December 31, 2002 – 2.9% (2001 – 2.5%) [b,c]	**548**	861
Bank debt, interest at December 31, 2002 – 3.5% (2001 – 2.6%) [b]	**199**	1 112
Total unsecured long-term debt	**2 562**	2 998
Other secured long-term debt with interest rates averaging 6.1% (2001 – 7.1%)	**5**	6
Capital leases [d,e]	**119**	109
Total long-term debt	**2 686**	3 113

(a) In 2002, the company issued 7.15% Notes with a principal amount of US$500 million (Cdn$ equivalent of $790 million at December 31, 2002). The net proceeds received were used to repay commercial paper and bank debt.

(b) The company has entered into various interest rate swap transactions at December 31, 2002. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transactions	Principal Swapped ($ millions)	Swap Maturity	2002 Effective Interest Rate
Swap of 6.70% Series 2 Medium Term Notes to floating rates	200	2011	4.0%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.5%
Swap of 6.10% Medium Term Notes to floating rates	150	2007	3.8%
Swap of floating rate Commercial Paper to fixed rates	110	2003	5.3%
Swap of U.S. dollar denominated floating rate debt to Canadian dollar denominated floating rates	US$126	2003	3.2%

(c) The company is authorized to issue commercial paper to a maximum of $900 million having a term not to exceed 364 days. Commercial paper is supported by unutilized credit and term loan facilities.

(d) Obligations under capital leases are as follows:

($ millions)	2002	2001
Energy services assets lease with interest at 6.82%, maturing in 2004	**101**	101
Other equipment leases with interest rates between prime plus 0.5% and 6.25%, and maturity dates ranging from 2008 to 2010	**18**	8
	119	109

(e) Future minimum amounts payable under capital leases and other long-term debt are as follows:

($ millions)	Capital Leases	Other Long-term Debt
2003	10	3
2004	110	324
2005	3	—
2006	3	550
2007	3	400
Later years	9	1 290
Total minimum payments	138	2 567
Less amount representing imputed interest	19	
Present value of obligation under capital leases	119	

Long-term Debt
(per cent)

	02	01
Variable rate	**46**	60
Fixed rate	**54**	40

Credit Facilities

At December 31, 2002, the company had available credit and term loan facilities of $1,948 million, of which $1,139 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of three years and expires in 2006	600
Facility for US$126 million that is non-revolving, has been fully drawn and expires in 2004	199
Facility that is fully revolving and expires in 2004	1 058
Undrawn facilities that can be terminated at any time at the option of the lenders	91
Total available credit facilities	1 948
Drawn from credit facilities	(199)
Credit facilities supporting commercial paper program and standby letters of credit	(610)
Total undrawn credit facilities	1 139

At December 31, 2002, the company had issued $62 million in letters of credit to various third parties.

5. Financial Instruments

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures manage the exposure to losses that could result if commodity prices or foreign currency exchange rates change adversely.

An option is a contract where its owner, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges can protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limits the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

See next page for more technical details and amounts.

(a) Balance Sheet Financial Instruments

The company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, investments in Southern Pacific Petroleum (SPP), substantially all current liabilities (except for income taxes payable and future income taxes), and long-term debt.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

(i) The fair values of cash and cash equivalents, accounts receivable and current liabilities approximate their carrying amounts due to the short-term maturity of these instruments.

(ii) The fair value of the company's investment in the shares of SPP is determined based on quoted market prices of these shares.

(iii) At December 31, 2002, the company had outstanding crude oil and U.S. dollar swap contracts maturing in 2004, fixing the purchase price of 2,130,000 barrels of crude oil at Cdn$49 million. These derivative contracts, which have not been accounted for as hedges, had a fair value and carrying value of $22 million at December 31, 2002 (2001 – $13 million; 2000 – $10 million) (see note 9c).

The following table summarizes estimated fair value information about the company's long-term debt at December 31:

	2002		2001	
($ millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term Debt				
Fixed-term	**1 815**	**1 991**	1 025	1 047
Revolving-term	**747**	**747**	1 973	1 974
Other	**5**	**5**	6	6
Capital leases	**119**	**119**	109	109

The fair values of the company's fixed and revolving-term long-term debt, capital leases, and other long-term debt were determined through comparisons to similar debt instruments.

(b) Unrecognized Derivative Financial Instruments

The company periodically is also a party to certain derivative financial instruments, which are not recognized in the consolidated balance sheets, as follows:

Revenue and Margin Hedges

The company periodically enters into crude oil and foreign currency swap and option contracts to protect its future Canadian dollar earnings and cash flows from the potential adverse impact of low petroleum prices and an unfavourable Canadian/U.S. dollar exchange rate. These contracts reduce fluctuations in sales revenues by locking in fixed prices, or a range of fixed prices, and exchange rates on the portion of its crude oil sales covered by the contracts. The company also enters into crude oil, gasoline and heating oil swap contracts to lock in fixed margins on the portion of refined product sales covered by the contracts. While these contracts reduce the risk of exposure to adverse changes in commodity prices and exchange rates, they also reduce the potential benefit of favourable changes in commodity prices and exchange rates.

The contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

Contracts outstanding at December 31 were as follows:

Crude Oil Hedges	Quantity (bbl/day)	Average Price[a] (US$/bbl)	Revenue Hedged (Cdn$ millions)	Hedge Period
As at December 31, 2002				
Crude oil swaps	**10 000**	**30**	**57** [c]	**2003** [b]
Crude oil swaps	**15 000**	**24**	**208** [c]	**2003**
Costless collars	**60 000**	**21 – 26**	**726 – 899** [c]	**2003**
Crude oil swaps	**25 000**	**23**	**332** [c]	**2004**
Costless collars	**11 000**	**21 – 24**	**133 – 152** [c]	**2004**
Crude oil swaps	**21 000**	**22**	**266** [c]	**2005**
As at December 31, 2001				
Crude oil swaps	40 576	20	444 [d]	2002
Crude oil swaps	424	21	5 [c]	2002
Costless collars	43 000	22 – 27	550 – 675 [c]	2002
Costless collars	44 000	21 – 26	537 – 665 [c]	2003
Costless collars	11 000	21 – 24	134 – 153 [c]	2004
Crude oil swaps	15 000	22	192 [c]	2005
As at December 31, 2000				
Crude oil swaps	42 710	20	436 [d]	2001
Crude oil swaps	4 790	20	52 [c]	2001
Costless collars	10 000	26 – 32	142 – 175 [c]	2001
Crude oil swaps	41 000	20	426 [d]	2002
Costless collars	7 000	22 – 26	84 – 1003 [c]	2002

Margin Hedges	Quantity (bbl/day)	Average Margin (US$/bbl)	Margin Hedged[c] (Cdn$ millions)	Hedge Period
Refined product sales and crude purchase swaps				
As at December 31, 2002	**20 700**	**5**	**9**	**2003** [e]
As at December 31, 2001	—	—	—	—
As at December 31, 2000	13 300	5	18	2001 [f]

(a) Average price for crude oil swaps is WTI per barrel at Cushing, Oklahoma.

(b) For the period January to April 2003, inclusive. All other crude oil positions are for the full year.

(c) The revenue and margin hedged is translated to Cdn$ at the year-end exchange rate and is subject to change as the Cdn$/US$ exchange rate fluctuates during the hedge period.

(d) The revenue hedged was fixed in Cdn$ as the company had foreign exchange swaps in place for these crude oil swaps.

(e) For the period January and February 2003.

(f) For the period January to June 2001.

Interest Rate Hedges

The company enters into interest rate and cross-currency interest rate swap contracts as part of its risk management strategy to manage its exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The cross-currency swap contracts involve an exchange of Canadian dollar interest payments and U.S. dollar interest payments, and an exchange of Canadian and U.S. dollar principal amounts at the maturity date of the underlying borrowing to which the swaps relate. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate and cross-currency interest rate swap contracts outstanding at December 31, 2002 are detailed in note 4, Long-term Debt.

Fair Value of Derivative Financial Instruments

The fair value of hedging derivative financial instruments is the estimated amount, based on brokers' quotes, that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2002**	2001
Revenue hedge swaps and options	**(133)**	54
Margin hedge swaps	**1**	(2)
Interest rate and cross-currency interest rate swaps	**35**	4
	(97)	56

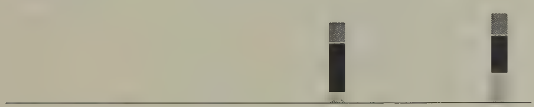
The fair value of the derivative financial instruments related to the company's trading activities are determined based on actively traded, quoted market prices. For the period ended December 31, 2002, gains or losses resulting from trading activities were not significant.

(c) Counterparty Credit Risk

The company may be exposed to certain losses in the event that counterparties to the derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. The company minimizes this risk by entering into agreements only with investment grade counterparties, and through regular management review of potential exposure to, and credit ratings of, such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	**2002**	2001
Derivative contracts not accounted for as hedges	**28**	12
Unrecognized derivative contracts	**23**	93
	51	105

6. Accrued Liabilities and Other



($ millions)	**02**	01
Reclamation and environmental remediation costs (a)	**57**	61
Employee future benefits (see note 7)	**141**	108
Other (b)	**28**	82
Total	**226**	251

(a) Reclamation and Environmental Remediation Costs

Total accrued reclamation and environmental remediation costs also include $32 million in current liabilities (2001 – $23 million). Payments during 2002 totalled $15 million (2001 – $28 million; 2000 – $15 million), while expense recorded in 2002 was $20 million (2001 – $15 million; 2000 – $13 million).

(b) Employee and Director Incentive Plans

Included in accrued liabilities and other is accrued compensation expense related to the company's employee long-term incentive plan (see note 11b). Accrued liabilities and other also include accrued compensation expense in the form of deferred share units received under the directors' compensation plan. Accrued directors' compensation expense is not significant.

7. Employee Future Benefits

*Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related **Benefit Obligation** or commitment that Suncor had to employees and retirees at December 31, 2002 was $586 million.*

*As required by government regulations and plan performance, Suncor sets aside funds, with an independent trustee, to meet certain of these obligations. At the end of December, 2002, **Plan Assets** to meet the **Benefit Obligation** were $273 million.*

*The excess of the **Benefit Obligation** over **Plan Assets** of $313 million represents the **Net Unfunded Obligation**.*

See below for more technical details and amounts.

Defined Benefit Pension Plans and Other Post-retirement Benefits

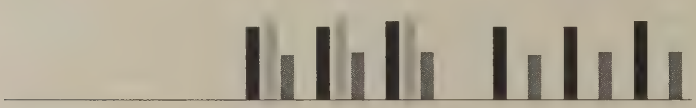
The company's defined benefit pension plans provide a pension benefit at retirement based on years of service and final average earnings. These obligations are met through a funded registered retirement plan and through unfunded, unregistered supplementary benefits that are paid directly to recipients. Company contributions to the funded plan are deposited with an independent trustee who acts as custodian of the funded pension plan assets, as well as the disbursing agent of the benefits to recipients. Plan assets are managed by an employee pension committee on behalf of beneficiaries. The committee retains independent managers and advisers.

Funding of the registered retirement plan complies with federal and provincial pension legislation that requires an actuarial valuation of the pension funds be performed at least once every three years. As a result of a recent triennial valuation of the registered plan, company funding of current and past service costs for 2003 is anticipated to be $45 million to $50 million (2002 – $14 million).

The company's other post-retirement benefits program, which is unregistered and unfunded, includes certain health care and life insurance benefits provided to retired employees and eligible surviving dependants. Retirees share in the cost of providing these benefits.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian generally accepted accounting principles and actuarial procedures. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement. Obligations are based on the following assumptions:

Assumptions
(per cent)



	Pension Benefits			Other Post-retirement Benefits		
	02	01	00	**02**	01	00
Discount rate	**6.50**	6.50	7.00	**6.50**	6.50	7.00
Expected return on plan assets	**7.25**	7.25	7.25	**—**	—	—
Rate of compensation increase	**4.00**	4.25	4.25	**4.00**	4.25	4.25

The following table presents information about the funded status of the plans and obligations recognized in the consolidated balance sheets at December 31:

($ millions)	Pension Benefits 2002	Pension Benefits 2001	Other Post-retirement Benefits 2002	Other Post-retirement Benefits 2001
Change in benefit obligation				
Benefit obligation at beginning of year	**461**	404	**93**	79
Service costs	**17**	14	**4**	3
Interest costs	**30**	28	**6**	6
Plan participants' contribution	**4**	3	**—**	—
Amendments	**—**	—	**(34)**	—
Actuarial (gain) loss	**(1)**	34	**30**	7
Benefits paid	**(22)**	(22)	**(2)**	(2)
Benefit obligation at end of year	**489**	461	**97**	93
Change in plan assets[(a)]				
Fair value of plan assets at beginning of year	**301**	322	**—**	—
Actual (loss) on plan assets	**(24)**	(14)	**—**	—
Employer contribution	**14**	12	**—**	—
Plan participants' contribution	**4**	3	**—**	—
Benefits paid	**(22)**	(22)	**—**	—
Fair value of plan assets at end of year	**273**	301	**—**	—
Net unfunded obligation	**(216)**	(160)	**(97)**	(93)
Items not yet recognized in earnings:				
Unamortized net actuarial loss[(b)]	**142**	109	**46**	19
Unamortized past service costs[(c)]	**—**	—	**(34)**	—
Accrued benefit liability	**(74)**	(51)	**(85)**	(74)
Current portion	**(16)**	(15)	**(2)**	(2)
Long-term portion (note 6)	**(58)**	(36)	**(83)**	(72)
	(74)	(51)	**(85)**	(74)

(a) Assets in the pension plan consist of investments in marketable equity securities, government and corporate bonds, and short-term notes. Pension plan assets are not the company's assets and therefore are not included in the consolidated balance sheets.

(b) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 13 years for pension benefits and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits. As a result of a recent triennial valuation, effective 2003, the expected average remaining service life of employees and the expected average future service life to full eligibility age will be 12 years and 10 years respectively.

(c) Effective April 1, 2003, the company will implement amendments to its existing post-retirement benefits program. Certain of the company's employees and all retirees will continue to receive post-retirement benefits under the current plan provisions. These plan amendments have reduced the company's other post-retirement benefits obligation at December 31, 2002, by $34 million.

The above benefit obligation at year-end includes funded and unfunded plans, as follows:

($ millions)	Pension Benefits 2002	Pension Benefits 2001	Other Post-retirement Benefits 2002	Other Post-retirement Benefits 2001
Funded plan	**423**	377	**—**	—
Unfunded plans	**66**	84	**97**	93
Benefit obligation at end of year	**489**	461	**97**	93

The components of net periodic benefit cost are as follows:

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2002**	2001	2000	**2002**	2001	2000
Current service costs	**17**	14	12	**4**	3	3
Interest costs	**30**	28	26	**6**	6	5
Expected return on plan assets[a]	**(22)**	(23)	(22)	**—**	—	—
Amortization of transitional asset	**—**	(8)	(8)	**—**	—	—
Amortization of net actuarial loss	**15**	9	6	**2**	1	1
Net periodic benefit cost	**40**	20	14	**12**	10	9

(a) The expected return on plan assets is the expected long-term rate of return on plan assets for the year based on plan assets at the beginning of the year that have been adjusted on a weighted average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 13 years for pension benefits, and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits. As a result of a recent triennial valuation, effective 2003, the expected average remaining service life of employees and the expected average future service life to full eligibility age will be 12 years and 10 years, respectively.

A 1% change in the assumptions at which pension benefits and other post-retirement benefits liabilities could be effectively settled is as follows:

	Rate of Return on Plan Assets		Discount Rate		Rate of Compensation Increase	
($ millions)	1% increase	1% decrease	1% increase	1% decrease	1% increase	1% decrease
Effect on net periodic benefit cost	(3)	3	(8)	10	4	(3)
Effect on benefit obligation	—	—	(71)	81	18	(16)

In order to measure the expected cost of other post-retirement benefits, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2002. Based upon recent experience, an assumption of 12% will be used for 2003, and then it is assumed this rate will decrease annually by a rate of 0.5% to 5% for 2017, and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for other post-retirement benefit obligations. A 1% change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Effect on total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(2)
Effect on the health care component of the accumulated post-retirement benefit obligation	9	(8)

Defined Contribution Pension Plan

The company has a defined contribution plan, under which both the company and employees make contributions. Company contributions and related expense totalled $5 million in 2002 (2001 – $4 million; 2000 – $4 million).

8. Income Taxes

*The assets and liabilities shown on Suncor's balance sheets are calculated using accounting rules known as generally accepted accounting principles. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as **temporary differences**, because eventually these differences will reverse.*

*The amount shown on the balance sheets as **future income taxes** represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.*

See below for more technical details and amounts.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

	2002		2001		2000	
($ millions)	Amount	%	Amount	%	Amount	%
Federal tax rate	**435**	**38**	195	38	236	38
Provincial abatement	**(114)**	**(10)**	(51)	(10)	(62)	(10)
Federal surtax	**13**	**1**	6	1	7	1
Provincial tax rates	**150**	**13**	69	14	96	16
Statutory tax and rate	**484**	**42**	219	43	277	45
Add (deduct) the tax effect of:						
Crown royalties	**39**	**3**	48	9	83	13
Resource allowance	**(34)**	**(3)**	(28)	(5)	(45)	(8)
Temporary difference in resource allowance	**(120)**	**(10)**	(49)	(10)	(56)	(9)
Large corporations tax	**17**	**1**	16	3	10	2
Tax rate changes on future income taxes	**(10)**	**(1)**	(52)	(11)	(13)	(2)
Attributed Canadian royalty income	**(2)**	**—**	(6)	(1)	(13)	(2)
Non-deductible foreign expenses	**—**	**—**	(17)	(3)	3	—
Assessments and adjustments	**10**	**1**	(11)	(2)	(3)	—
Other	**(1)**	**—**	5	1	—	—
Income taxes and effective rate	**383**	**33**	125	24	243	39

In 2002 net income tax refunds totalled $8 million (2001 – $23 million payment; 2000 – $22 million payment).

The resource allowance is a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by generally accepted accounting principles in Canada, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate (currently 25%) applied to those temporary differences that are factored into the determination of the resource allowance.

For the three years ended December 31, 2002, the resource allowance resulted in a net decrease in the company's effective tax rate due primarily to the difference between depreciation for tax and accounting purposes. To the extent that these temporary differences reverse in future years and are not offset by the effect of new capital expenditures, the company's effective tax rate will increase.

At December 31, future income taxes are comprised of the following:

	2002		2001	
($ millions)	Current	Non-current	Current	Non-current
Future income tax assets:				
Employee future benefits	**4**	**48**	4	30
Reclamation and environmental remediation costs	**10**	**17**	8	19
Alberta royalties	**—**	**43**	—	44
Employee incentive plans	**—**	**16**	—	29
Inventories	**18**	**—**	11	—
Other	**6**	**11**	6	10
	38	**135**	29	132
Future income tax liabilities:				
Depreciation	**—**	**1 473**	—	1 105
Overburden removal costs	**—**	**20**	—	30
Maintenance shutdown costs	**—**	**15**	—	10
Inventories	**—**	**—**	10	—
Other	**10**	**8**	18	32
	10	**1 516**	28	1 177

9. Commitments and Contingencies

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2002, future minimum amounts payable under these leases and agreements were as follows:

($ millions)	Pipeline Capacity and Energy Services [(a)]	Operating Leases
2003	162	54
2004	161	46
2005	167	39
2006	176	34
2007	177	22
Later years	4 108	61
	4 951	256

(a) Includes annual tolls payable under a transportation service agreement with a major pipeline company to use a portion of its pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreement commenced in 1999 and extends to 2028. As the initial shipper on the pipeline, Suncor's tolls payable under the agreement could be subject to annual adjustments.

To meet the energy needs of its oil sands operation, Suncor has a commitment under long-term energy agreements to obtain a portion of the power and all of the steam generated by a cogeneration facility owned by a major energy company. Since October 1999, this company has managed the operations of Suncor's existing energy services facility.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated reclamation and environmental remediation costs. These costs are accrued at the company's Natural Gas and Oil Sands operations on the unit of production basis. A provision is not made for currently operated facilities such as the Oil Sands processing facilities, the Sarnia refinery and service stations until cessation of operations and completion of site investigations. Any changes in environmental remediation estimates (net of estimated gains on sale of sites) will affect future earnings. These estimates could change significantly based upon such factors as operating experience, changes in legislation and regulations and cost.

To mitigate its exposure to property and business interruption losses, the company has purchased insurance policies with a combined coverage of up to US$1,150 million, net of deductible amounts. The policies stipulate a property loss deductible of US$10 million per incident, and a business interruption loss deductible per incident, based on the greater of US$50 million or 30 days of gross earnings lost (as defined in the respective insurance policies). Gross earnings can be influenced by such factors as production levels and commodity prices.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not be expected to have a material effect on the company's consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash provided from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Special Purpose Entities and Guarantees

At December 31, 2002, the company had various off-balance sheet arrangements with Special Purpose Entities and indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2002, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses to a maximum of $53 million. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2002, were approximately $4 million and $2,421 million, respectively. The company recorded an after-tax loss of approximately $3 million on the securitization program in each of the last three years.

In 1999, the company sold 2,130,000 barrels of its crude oil inventory for $49 million to a third party while retaining the right to use the inventory for its operations through a usage agreement for a five-year period. The third party's sole asset is the inventory sold to it by the company. The company pays an annual usage fee of $7 million to the third party and receives a $4 million annual storage fee. The company has the right, but is not obligated, to repurchase the inventory at the spot price at the end of the agreement in 2004. In order to reduce the exposure to the spot price should it elect to repurchase the inventory, the company had, at December 31, 2002, crude oil and U.S. dollar swap contracts fixing the purchase price of the crude oil at Cdn$49 million.

In 1999, the company entered into an equipment sale and leaseback arrangement with a third party for proceeds of $30 million. The third party's sole asset is the equipment sold to it and leased back by the company. The initial lease term covers a period of seven years and is accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. An early termination purchase option allows for the repurchase of the equipment at specified dates in 2003, 2004 and 2005. Had the company elected to terminate the lease at December 31, 2002, the total cost would have been $32 million. Lease payments by the company in each of the last three years were $2 million per year.

The company has agreed to indemnify lenders of the 9.125% preferred securities, the 7.15% notes and the company's credit facilities (see note 4) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, the crude oil inventory monetization agreement and certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

10. Preferred Securities

During 1999, the company completed a Canadian offering of $276 million of 9.05% preferred securities and a U.S. offering of US$162.5 million of 9.125% preferred securities for net proceeds of Cdn$507 million after issue costs of $17 million ($10 million after income taxes). The preferred securities are comprised of unsecured junior subordinated debentures, due in 2048 and redeemable at the company's option on or after March 15, 2004 for proceeds equal to the original principal amount of the preferred securities plus any accrued and unpaid interest as at the date of redemption. Subject to certain conditions, the company has the right to defer payment of interest on the securities for up to 20 consecutive quarterly periods. Deferred interest and principal amounts are payable in cash, or, at the option of the company, from the proceeds on the sale of equity securities of the company delivered to the trustee of the preferred securities. Accordingly, the preferred securities are classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, are classified as dividends. Proceeds from the offerings were used to repay commercial paper debt.

In 2002, dividends of $48 million were paid on the preferred securities (2001 – $48 million; 2000 – $47 million).

11. Share Capital

(a) Authorized:

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

(b) Issued:

The number of common shares and common share options outstanding, common share prices and per share calculations, for both current and prior periods, reflect a two-for-one split of the company's common shares during 2002.

	Common Shares	
($ millions)	Number	Amount
Balance as at December 31, 2000	443 801 158	537
Issued for cash under stock option plans	2 096 138	15
Issued under dividend reinvestment plan	59 194	3
Balance as at December 31, 2001	445 956 490	555
Issued for cash under stock option plans	1 776 433	19
Issued under employee long-term incentive plan	1 089 888	—
Issued under dividend reinvestment plan	148 732	4
Balance as at December 31, 2002	**448 971 543**	**578**

Common Share Options

A stock option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees that hold options must earn the rights to exercise them. This is done by the employee fulfilling a time requirement for service to the company, and with respect to certain options, subject to accelerated vesting should the company meet predetermined performance criteria. Once this right has been earned, these options are considered vested. Options granted to non-employee directors vest and are exercisable immediately.

The predetermined price at which an option can be exercised is generally equal to or greater than the market price of the common shares on the date the options are granted.

See below for more technical details and amounts on the company's stock option plans:

(i) EXECUTIVE STOCK PLAN Under this plan, the company granted 1,802,650 common share options in 2002 to non-employee directors and certain executives and other senior employees of the company. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted to non-employee directors have a 10-year life and are exercisable immediately. Options granted to employees have a 10-year life and vest annually over a three-year period.

(ii) EMPLOYEE LONG-TERM INCENTIVE PLAN Suncor's employee long-term incentive plan was adopted in 1997 and matured on April 1, 2002. At maturity, employees received 1,089,888 common shares from treasury for nil cash consideration, along with aggregate cash payments of $34 million. In addition, 2,131,517 common share options, previously granted to senior employees, vested and became exercisable. The company expensed the cash payments to employees of $34 million as pretax compensation expense over the five-year life of the plan. No compensation expense was recorded related to the employees' receipt of common shares from treasury as these common shares were treated as stock option grants.

Concurrently, 1,461,886 deferred share units (DSUs) with a cash settlement value of $42 million, which had previously been granted to certain executives, vested. These executives also received cash payments of $44 million. As of April 1, 2002, the company had recorded total pretax compensation expense of $86 million related to the executive portion of the company's long-term incentive plan over the five-year life of the plan.

DSUs are only redeemable at the time a unitholder ceases employment. Subsequent to April 1, 2002, 220,347 DSUs were redeemed for cash consideration of $6 million, resulting in total cash payments made to executives during 2002 of $50 million. Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. From April to December of 2002, an additional 6,495 DSUs were issued pursuant to this dividend reinvestment feature.

Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2002, 1,248,034 DSUs were outstanding with a total liability of $31 million, of which $27 million was classified as long-term (see note 6).

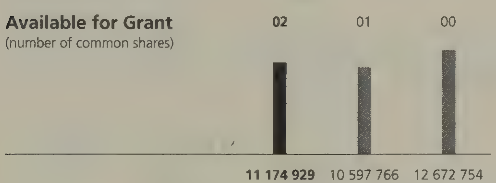
During 2002, total pretax compensation expense recorded under the company's long-term incentive plans to employees, senior management and executives was $10 million (2001 – $42 million; 2000 – $32 million). For the five-year period ended April 1, 2002, total pretax compensation expense was $120 million.

(iii) SUNSHARE PERFORMANCE STOCK OPTION PLAN During 2002, the company granted 8,937,992 options to all eligible permanent full-time and part-time employees, both executive and non-executive, under its new employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets may accelerate the vesting of some or all options, such that 20% of outstanding options may vest as early as 2004, up to an additional 20% of outstanding options may vest as early as 2005 and the remaining 60% of outstanding options may vest on April 30, 2008. All unvested options which have not previously expired or been cancelled will automatically vest on January 1, 2012.

The following tables cover all common share options granted by the company for the years indicated:

	Number	Exercise Prices	Weighted-average Exercise Price
Outstanding, December 31, 1999	11 715 972	2.38 – 15.09	9.01
Granted	1 900 032	13.04 – 19.28	15.65
Exercised	(1 474 404)	2.38 – 12.28	6.29
Cancelled	(419 850)	10.13 – 16.52	13.02
Outstanding, December 31, 2000	11 721 750	2.38 – 19.28	10.28
Granted	2 180 720	15.94 – 21.35	17.63
Exercised	(2 028 668)	2.38 – 16.48	7.30
Cancelled	(105 732)	10.13 – 20.20	14.21
Outstanding, December 31, 2001	11 768 070	2.38 – 21.35	12.12
Granted	10 740 642	23.93 – 28.14	27.08
Exercised	(1 776 433)	2.38 – 17.45	10.42
Cancelled	(406 028)	13.04 – 27.65	26.48
Outstanding, December 31, 2002	**20 326 251**	**3.80 – 28.14**	**19.89**
Exercisable, December 31, 2002	**8 580 913**	**3.80 – 28.14**	**11.85**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:



The following table is an analysis of outstanding and exercisable common share options as at December 31, 2002:

	Outstanding			Exercisable	
Exercise Prices	Number	Weighted-average Remaining Contractual Life	Weighted-average Exercise Price	Number	Weighted-average Exercise Price
3.80 – 7.85	2 248 328	3 years	6.37	2 248 328	6.37
10.13 – 14.41	4 183 137	5 years	11.93	4 183 130	11.93
15.09 – 19.28	3 435 486	8 years	16.70	1 888 504	16.48
20.20 – 28.14	10 459 300	9 years	27.02	260 951	24.35
Total	20 326 251	7 years	19.89	8 580 913	11.85

(iv) FAIR VALUE OF OPTIONS GRANTED The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the year and the weighted-average assumptions used in their determination are as noted below:

	2002	2001	2000
Annual dividend per share	**$0.17**	$0.17	$0.17
Risk-free interest rate	**5.39%**	5.07%	6.45%
Expected life	**8 years**	5 years	7 years
Expected volatility	**31%**	35%	37%
Weighted-average fair value per option	**$12.08**	$6.41	$7.12

The company does not recognize any compensation costs related to stock options granted to employees and non-employee directors. Had compensation cost been determined based on the fair values at the grant dates, the cost of which is recognized over the vesting periods of the options granted, the company's net earnings and earnings per share would have been reduced to the amounts below:

($ millions, except per share amounts)	**2002**	2001	2000
Net earnings attributable to common shareholders – as reported	**734**	351	345
Less: compensation cost under the fair value method	**32**	9	7
Pro forma net earnings attributable to common shareholders	**702**	342	338
Basic earnings per share			
As reported	**1.64**	0.79	0.78
Pro forma	**1.57**	0.77	0.76
Diluted earnings per share			
As reported	**1.61**	0.78	0.77
Pro forma	**1.54**	0.76	0.75

12. Earnings Per Common Share

The following is a reconciliation of basic and diluted earnings per common share:

($ millions)	**2002**	2001	2000
Net earnings attributable to common shareholders	**734**	351	345
Dividends on preferred securities, net of tax	**28**	—(a)	—(a)
Revaluation of US$ preferred securities, net of tax	**(1)**	—(a)	—(a)
Adjusted net earnings attributable to common shareholders	**761**	351	345
(millions of common shares)			
Weighted-average number of common shares	**448**	445	443
Dilutive securities:			
Options issued under stock-based compensation plans	**5**	6	4
Redemption of preferred securities by the issuance of common shares	**20**	—(a)	—(a)
Weighted-average number of diluted common shares	**473**	451	447
(dollars per common share)			
Basic earnings per share(b)	**1.64**	0.79	0.78
Diluted earnings per share	**1.61(c)**	0.78(a)	0.77(a)

Common share and earnings per common share amounts in the above table reflect a two-for-one share split effective May 15, 2002.

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) For the years ended December 31, 2001 and 2000, diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares. Dividends on preferred securities, the revaluation of US$ preferred securities and the redemption of preferred securities by the issuance of common shares have an anti-dilutive impact, therefore they are not included in the calculation of diluted earnings per share.

(b) Basic earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

(c) Diluted earnings per share is the adjusted net earnings attributable to common shareholders, divided by the weighted-average number of diluted common shares.

13. Financing Expenses

($ millions)	2002	2001	2000
Interest on debt	**155**	143	112
Capitalized interest	**(22)**	(125)	(104)
Net interest expense	**133**	18	8
Foreign exchange (gain) on long-term debt and other	**(9)**	(2)	—
Total financing expenses	**124**	16	8

Cash interest payments in 2002 totalled $134 million (2001 – $129 million; 2000 – $104 million).

14. Inventories

(Cdn$ millions)	02	01
Materials and supplies	**75**	72
Refined products	**90**	71
Crude oil	**101**	115
Total	**266**	258

The replacement cost at December 31, 2002, of crude oil and refined product inventories valued at LIFO exceeded their carrying value by $84 million (2001 – $5 million).

15. Accounting for Intersegment Revenues

In 2001, the company changed the methodology of accounting for sales from its upstream operations to its downstream operations from a deeming concept to one based on actual product shipments.

The impact of this prospective change in methodology on 2002 was to increase both operating revenues and purchases of crude oil and products by $1,164 million (2001 – $473 million). There was no impact on consolidated and segmented net earnings.

16. Sales of the Retail Natural Gas Marketing Business and Oil Shale Project

(a) In 2002, the company sold its retail natural gas marketing business in the Energy Marketing and Refining segment for cash consideration of $62 million, net of related closing costs and adjustments of $4 million, resulting in an after-tax gain of $35 million.

(b) In 2001, the company sold its interest in the Stuart Oil Shale Project for consideration of $5 million comprised of common shares and share options in SPP. During 2002, the company reduced the carrying value of the SPP shares by $1 million (2001 – $3 million) to reflect the decline in their value.

17. Related Party Transactions

The following table summarizes the company's related party transactions before eliminations for the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

($ millions)	2002	2001	2000
Operating revenues			
Sales to Energy Marketing and Refining segment joint ventures:			
Refined products	**612**	602	600
Petrochemicals	**142**	131	128

The company has exclusive supply agreements with two Energy Marketing and Refining segment joint ventures for the sale of refined products. The company also has a non-exclusive supply agreement with an Energy Marketing and Refining segment joint venture for the sale of petrochemicals.

Sales to and balances with Energy Marketing and Refining segment joint ventures are established and agreed to by the related parties and approximate fair value.

At December 31, 2002, amounts due from Energy Marketing and Refining segment joint ventures were $46 million (2001 – $33 million).

18. Supplemental Information

($ millions)	2002	2001	2000
Export sales[(a)]	**501**	590	478
Exploration expenses			
Geological and geophysical	**13**	11	10
Other	**2**	1	2
Cash costs	**15**	12	12
Dry hole costs	**11**	10	41
Cash and dry hole costs[(b)]	**26**	22	53
Leasehold impairment[(c)]	**10**	9	10
	36	31	63
Taxes other than income taxes			
Excise taxes[(d)]	**340**	343	336
Production, property and other taxes	**34**	24	25
	374	367	361
Allowance for doubtful accounts	**3**	3	

(a) Sales of crude oil, natural gas and refined products to customers in the United States and sales of petrochemicals to customers in the United States and Europe.

(b) Included in exploration expenses in the Consolidated Statements of Earnings.

(c) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

(d) Included in operating revenues in the Consolidated Statements of Earnings.

In 2000, the carrying values of certain assets of the company's Natural Gas business were written down to their net estimated recoverable amount and a provision for estimated restructuring costs was recorded. During 2001, some of these properties that were previously written down were sold and provisions for estimated restructuring costs were revised to reflect increased employee termination costs. The impact of these adjustments on 2002 is nil (2001 – increased net earnings by $1 million; 2000 – decreased net earnings by $30 million).

19. Differences Between Canadian and United States Generally Accepted Accounting Principles

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on earnings and comprehensive income as reported:

($ millions)	Notes	2002	2001	2000
Net earnings as reported, Canadian GAAP		**761**	388	377
Adjustments net of applicable income taxes				
Stock-based compensation	(b)	**(12)**	(14)	(22)
Preferred securities	(c)	**(29)**	(27)	(22)
Start-up costs	(d)	**—**	10	8
Income taxes	(e)	**—**	6	(6)
Write-off of oil shale assets	(f)	**—**	64	(64)
Derivatives and hedging activities	(a)	**6**	(55)	—
Cumulative effect of change in accounting principles	(a)	**—**	47	—
Net (earnings) loss attributable to discontinued operations	(g)	**(56)**	5	5
Net earnings from continuing operations, U.S. GAAP		**670**	424	276
Net earnings (loss) from discontinued operations, U.S. GAAP	(g)	**56**	(5)	(5)
Minimum pension liability, net of income taxes of $10 (2001 – $11; 2000 – $1)	(h)	**(20)**	(26)	(2)
Derivatives and hedging activities, net of income taxes of $54 (2001 – $16)	(a)	**(118)**	29	—
Comprehensive income, U.S. GAAP		**588**	422	269

Per common share (dollars)		2002	2001	2000
Net earnings per share from continuing operations				
Basic		**1.50**	0.95	0.62
Diluted		**1.47**	0.94	0.62
Net earnings per share from discontinued operations				
Basic		**0.12**	(0.01)	(0.01)
Diluted		**0.12**	(0.01)	(0.01)

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		2002		2001	
($ millions)	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Total current assets	(a)	**722**	**767**	622	694
Property, plant and equipment, net	(c)	**7 641**	**7 674**	7 141	7 174
Deferred charges and other	(a,c,h)	**185**	**231**	199	210
Future income taxes	(a,c,h)	**135**	**165**	132	159
Total assets		**8 683**	**8 837**	8 094	8 237
Total current liabilities	(a)	**797**	**933**	773	806
Long-term debt	(a,c)	**2 686**	**3 251**	3 113	3 649
Accrued liabilities and other	(b,h)	**226**	**306**	251	336
Future income taxes	(a,c)	**1 516**	**1 539**	1 177	1 220
Preferred securities	(c)	**523**	**—**	525	—
Share capital and additional paid-in capital	(b)	**578**	**626**	555	555
Retained earnings		**2 357**	**2 319**	1 700	1 670
Accumulated other comprehensive income	(a,h)	**—**	**(137)**	—	1
Total liabilities and shareholders' equity		**8 683**	**8 837**	8 094	8 237

(a) Derivative Financial Instruments

The company accounts for its derivative financial instruments under Canadian GAAP as described in note 5 to the Consolidated Financial Statements. Statement 133 "Accounting for Derivative Instruments and Hedging Activities", as amended by Statement 138, (the Standards), establishes U.S. GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk, are recognized in the statements of earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") and are recognized in the statements of earnings when the hedged item is recognized. Accordingly, ineffective portions of changes in the fair value of hedging instruments are recognized in earnings immediately for both fair value and cash flow hedges. Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same earnings statement caption as the hedged item. Gains or losses from derivative instruments for which hedge accounting is not applied are reported in other income.

Adoption of the Standards

For U.S. GAAP purposes, the company's adoption of Statement 133 effective January 1, 2001 would have increased assets by $176 million, increased liabilities by $302 million, decreased OCI by $173 million, net of income taxes of $87 million, and increased net income due to the cumulative effect of a change in accounting principles by $47 million, net of income taxes of $28 million.

Commodity Price Risk

The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of market prices for its petroleum and natural gas products. The company manages its Canadian dollar crude price exposure by entering into U.S. dollar WTI derivative transactions and in some instances combines U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2002 the company had hedged a portion of its future cash flows subject to commodity price risk for up to three years.

Interest Rate Risk

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to changes in cash flows of interest-bearing debt. At December 31, 2002 the company has interest rate derivatives classified as cash flow hedges outstanding for one year and fair value hedges outstanding for nine years.

During 2001, the company terminated the cross-currency interest rate swaps related to its Series C 7.4% Debentures. For Canadian GAAP purposes, the resulting gain of $4 million, net of income taxes of $2 million, has been deferred and is being amortized over the term to maturity of the Debentures, resulting in a decrease in interest expense during the year ended December 31, 2002 of $1 million, net of income taxes of $1 million. For U.S. GAAP purposes, the entire $4 million gain would have been recognized during 2001.

Non-designated Hedging Instruments

In 1999, the company sold inventory and subsequently entered into a derivative contract with an option to repurchase the inventory at the end of five years. The company realized an economic benefit as a result of liquidating a portion of its inventory. The derivative did not qualify for hedge accounting as the company does not have purchase price risk associated with the repurchase of the inventory. This derivative does not represent a U.S. GAAP difference as the company records this derivative at fair value for Canadian purposes.

During the fourth quarter of 2001, the company made a payment of $29 million to terminate a long-term natural gas contract. The contract had been designated as a hedge under Canadian GAAP, and the resulting settlement loss of $18 million, net of income taxes of $11 million, was to be deferred and recognized as the hedged item was settled. During 2002, in connection with the sale of the company's retail natural gas marketing business (see note 19g), the company disposed of the related hedged item. Accordingly, for Canadian GAAP purposes, the company recognized the entire settlement loss of $18 million during 2002. For U.S. GAAP purposes, the long-term contract would have been designated as a normal purchase and sale transaction, and the after-tax loss of $18 million would have been recognized in 2001 on the initial settlement of the contract.

The company has entered into a cross-currency interest rate swap related to US$126 million of variable rate debt. Although the swap transaction could have qualified as a fair value hedge of the related foreign currency risk had it been designated as such, the company chose not to designate it. Accordingly, the company has valued the swap at fair value and the debt has been revalued at the rate in effect at the related balance sheet date. Had the swap been designated as a fair hedge, the net effect on the company's net income would have been the same.

Accumulated OCI

A reconciliation of changes in accumulated OCI to derivative hedging activities for the years ended December 31 is as follows:

($ millions)	2002	2001
Accumulated OCI attributable to derivatives and hedging activities, beginning of period, net of income taxes of $13	**29**	—
Net hedging losses arising from implementation of the Standards, net of income taxes of $87	**—**	(173)
Current period net hedging losses arising from cash flow hedges, net of income taxes of $57 (2001 – $38)	**(123)**	79
Net hedging losses at beginning of the period reclassified to earnings during the period, net of income taxes of $3 (2001 – $62)	**5**	123
Accumulated OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $41 (2001 – $13)	**(89)**	29

During the year ended December 31, 2002, assets increased by $87 million and liabilities increased by $178 million as a result of recording all derivative instruments at fair value.

The loss associated with hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $19 million, net of income taxes of $9 million (2001 – $32 million, net of income taxes of $15 million). The company estimates that $72 million of hedging losses will be reclassified from OCI to current period earnings within 2003 as a result of forecasted sales occurring.

(b) Stock-based Compensation

Under Canadian GAAP, compensation expense has not been recognized for common share options granted in connection with the company's new SunShare long-term incentive plan. Under U.S. GAAP, certain of these options would have been accounted for using the variable method of accounting for employee stock compensation. As at December 31, 2002 no compensation expense would have been recognized on these options for U.S. GAAP purposes.

Under Canadian GAAP, compensation expense has not been recognized for common share options, including the common shares received by employees as described in note 11b under the company's previous long-term employee incentive plan that matured April 1, 2002. Under U.S. GAAP, compensation expense would have been recognized ratably over the life of the incentive plan for these options and common shares. For the year ended December 31, 2002, net earnings would have been reduced by $12 million (2001 – $14 million; 2000 – $22 million). As settlement of the incentive plan was made through issuance of options and common stock from treasury, share capital and additional paid-in capital was increased by $48 million.

Under Canadian GAAP, had the company accounted for its stock options using the fair value method, pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2002 would have been reduced by $32 million (2001 – $9 million; 2000 – $7 million) and $0.07 per share (2001 – $0.02; 2000 – $0.02), respectively. Under U.S. GAAP, had the company accounted for its options using the fair value method (excluding the SunShare and long-term employee incentive options identified above), pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2002 would have been reduced by $24 million (2001 – $9 million; 2000 – $7 million) and $0.05 per share (2001 – $0.02; 2000 – $0.02), respectively.

(c) Preferred Securities

Under Canadian GAAP, preferred securities are classified as share capital and the interest distributions thereon, net of income taxes, are accounted for as dividends. Under U.S. GAAP, the preferred securities would have been classified as long-term debt and the interest distributions thereon would have been accounted for as financing expenses. Preferred securities denominated in U.S. dollars of US$163 million would have been revalued at the rate in effect at the related balance sheet date, with any foreign exchange gains (losses) recognized in the statements of earnings. Further, under U.S. GAAP the interest distributions would have been eligible for interest capitalization.

Under Canadian GAAP, issue costs of the preferred securities, net of the related income tax credits, are charged against share capital. Under U.S. GAAP, these issue costs would have been deferred and amortized to earnings over the term of the related long-term debt.

The impact of these differences would have reduced net earnings for U.S. GAAP purposes for the year ended December 31, 2002 by $29 million, net of income taxes of $20 million (2001 – $27 million, net of income taxes of $18 million; 2000 – $22 million, net of income taxes of $17 million).

Under Canadian GAAP, the 2002 interest distributions on the preferred securities for the year ended December 31, 2002 of $48 million (2001 – $48 million; 2000 – $47 million) are classified as financing activities in the consolidated statements of cash flows. Under U.S. GAAP, the interest distributions and the amortization of issue costs for the year ended December 31, 2002 of $3 million (2001 – $3 million; 2000 – $7 million) would have been classified as operating activities.

The preferred securities, which are publicly traded, had a fair value, based on quoted market prices, of $568 million at December 31, 2002 (2001 – $575 million; 2000 – $544 million).

(d) Start-up Costs

In 2001, under Canadian GAAP, all remaining capitalized start-up costs associated with the Stuart Oil Shale Project were written down. Under U.S. GAAP, these start-up costs would have been fully expensed in 1999. As a result, net earnings for U.S. GAAP purposes for 2001 would have been increased by $10 million, net of income taxes of $7 million (2000 – increased net earnings by $8 million, net of income taxes of $6 million).

(e) Income Taxes

Under Canadian GAAP, changes in tax laws and rates are recognized when they are considered substantially enacted, whereas under U.S. GAAP, changes in tax laws and rates are only considered after they have been enacted into law. The impact of this GAAP difference would have been to increase U.S. GAAP net earnings for the year ended December 31, 2001 by $6 million (2000 – decrease net earnings by $6 million).

(f) Asset Impairment

Under Canadian GAAP, the company reduced the carrying amount of its interest in the Stuart Oil Shale Project in 2000, based on a non-discounted cash flow analysis. Had the carrying amount been determined using a discounted cash flow analysis as required under U.S. GAAP, an additional write-down of $64 million, net of income taxes of $55 million, would have been recorded in 2000. Effective April 5, 2001, the company sold its interest in the project. Due to the difference in determining the carrying value of the project for Canadian and U.S. GAAP purposes in 2000, net earnings for U.S. GAAP purposes for the year ended December 31, 2001 would have increased by $64 million.

(g) Discontinued Operations

During 2002, the company disposed of its retail natural gas marketing business for net proceeds of $62 million, and recognized a $35 million after-tax gain on the sale for Canadian GAAP purposes. The retail natural gas marketing business was not considered significant to the company's overall business operations, and was not classified as a business segment for the purposes of discontinued operations reporting. Accordingly, financial results of the retail natural gas marketing business were not segregated from the financial results of the company's other operations prior to the date of disposal of the business.

For U.S. GAAP purposes, the company would have adopted Statement 144 "Accounting for the Impairment and Disposal of Long-Lived Assets," effective January 1, 2002. For the purposes of Statement 144, the retail natural gas marketing business would have been considered a distinguishable component of the company, and reflected as a discontinued operation for the three years ended December 31, 2002. For segmented reporting purposes, the retail natural gas marketing business was included in the Energy Marketing and Refining operating segment in 2002, 2001 and 2000.

Selected financial information regarding the discontinued retail natural gas marketing business for U.S. GAAP purposes is as follows for the years ended December 31:

($ millions)	**2002**	2001	2000
Revenues from discontinued operations	**81**	196	116
Income (loss) from discontinued operations,			
net of income taxes of $4 (2001 – $3; 2000 – $3)	**8**	(5)	(5)
Gain on disposal of discontinued operations, net of income taxes of $10	**48**	—	—

Assets and liabilities related to the discontinued operations as at December 31 were comprised as follows:

($ millions)	**2002**	2001
Accounts receivable	—	20
Accounts payable	—	54

(h) Minimum Pension Liability

Under U.S. GAAP, recognition of an additional minimum pension liability is required when the accumulated benefit obligation exceeds the fair value of plan assets to the extent that such excess is greater than accrued pension costs otherwise recorded. No such adjustment is required under Canadian GAAP.

Under U.S. GAAP, at December 31, 2002, the company would have recognized a minimum pension liability of $80 million (2001 – $52 million; 2000 – $3 million), an intangible asset of $10 million (2001 – $12 million; 2000 – nil) and other comprehensive loss of $48 million, net of income taxes of $22 million (2001 – $28 million, net of income taxes of $12 million). Other comprehensive income for the year ended December 31, 2002, would have been reduced by $20 million, net of income taxes of $10 million (2001 – $26 million, net of income taxes of $11 million; 2000 – $2 million, net of income taxes of $1 million).

(i) Shipping and Handling Costs

The company reports upstream shipping and handling costs billed to customers as a reduction of operating revenues. Under U.S. GAAP, amounts billed to customers for shipping and handling are classified as revenues. The related shipping and handling costs are classified as expenses.

This impact is one of reclassification only and does not affect net earnings. The result would have been to increase operating revenues and operating, selling and general expenses for the year ended December 31, 2002 by $128 million (2001 – $95 million; 2000 – $96 million), respectively.

Recently Issued Accounting Standards

Asset Retirement Obligations

In August 2001, Statement 143, "Accounting for Asset Retirement Obligations," was issued. This statement changes the method and timing of accruing for costs arising from legal obligations associated with the retirement of tangible capital assets and the associated asset retirement costs. The company is continuing to evaluate the U.S. GAAP impact of implementing Statement 143, effective January 1, 2003.

Exit or Disposal Activities

In June 2002, Statement 146, "Accounting for Costs Associated with Exit or Disposal Activities," was issued. Statement 146 supercedes previous accounting guidance, principally Emerging Issues Task Force (EITF) No. 94-3. Statement 146 applies to exit and disposal activities initiated after December 31, 2002 and requires that the fair value of a liability for a cost associated with an exit or disposal activity be recognized in the period in which the liability is incurred. Under EITF 94-3, a liability was to be recognized at the date of the company's commitment to an exit plan. The company is not currently engaged in any exit or disposal activities.

Stock-based Compensation, Transition and Disclosure

Statement 148, "Accounting for Stock-based Compensation, Transition and Disclosure," issued in December 2002, provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Statement 148 also requires that disclosures of the pro forma effect of using the fair value method be displayed in a tabular format in both annual and interim reports. Statement 148 is effective for the company's 2002 fiscal year. The company has no current plans to adopt the fair value method of accounting for stock-based compensation. The pro forma effect of using the fair value method is disclosed in (b) Stock-based Compensation above.

Variable Interest Entities

Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities" (VIE), was issued in January 2003 (see Special Purpose Entities as described in note 9c). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the other equity investors do not have a controlling financial interest in, or do not have sufficient equity at risk to allow the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the company's third quarter 2003 interim report. The company is currently evaluating the effect that possible consolidation of these VIEs may have on its results of operations and financial condition.

QUARTERLY SUMMARY

(unaudited)

FINANCIAL DATA

($ millions except per share amounts)	For the Quarter Ended Mar 31 2002	June 30 2002	Sept 30 2002	Dec 31 2002	Total Year 2002	For the Quarter Ended Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001	Total Year 2001
Revenues	**1 051**	**1 260**	**1 225**	**1 368**	**4 904**	1 087	1 156	1 051	905	4 199
Net earnings (loss)										
Oil Sands	**111**	**202**	**234**	**246**	**793**	69	108	69	37	283
Natural Gas	**5**	**12**	**1**	**17**	**35**	53	39	13	12	117
Energy Marketing and Refining	**7**	**26**	**9**	**19**	**61**	23	45	12	—	80
Corporate and eliminations	**(33)**	**(11)**	**(60)**	**(24)**	**(128)**	(20)	(28)	(21)	(23)	(92)
	90	**229**	**184**	**258**	**761**	125	164	73	26	388
Per common share										
Net earnings attributable to common shareholders										
Basic	**0.18**	**0.52**	**0.38**	**0.56**	**1.64**	0.25	0.37	0.13	0.04	0.79
Diluted	**0.18**	**0.51**	**0.37**	**0.55**	**1.61**	0.24	0.36	0.13	0.04	0.78
Cash dividends	**0.0425**	**0.0425**	**0.0425**	**0.0425**	**0.17**	0.0425	0.0425	0.0425	0.0425	0.17
Cash flow provided from (used in) operations										
Oil Sands	**213**	**368**	**444**	**455**	**1 480**	140	117	139	90	486
Natural Gas	**34**	**41**	**36**	**53**	**164**	127	76	42	35	280
Energy Marketing and Refining	**28**	**(2)**	**34**	**47**	**107**	50	67	30	18	165
Corporate and eliminations	**(94)**	**(55)**	**(67)**	**(95)**	**(311)**	(42)	(14)	(34)	(10)	(100)
	181	**352**	**447**	**460**	**1 440**	275	246	177	133	831

OPERATING DATA

	For the Quarter Ended Mar 31 2002	June 30 2002	Sept 30 2002	Dec 31 2002	Total Year 2002	For the Quarter Ended Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001	Total Year 2001
OIL SANDS (thousands of barrels per day)										
Production	**179.3**	**207.6**	**207.9**	**227.6**	**205.8**	113.4	109.7	116.5	153.0	123.2
Sales										
Light sweet crude oil	**96.8**	**90.8**	**114.1**	**116.7**	**104.7**	53.0	55.0	54.2	62.4	56.2
Diesel	**20.2**	**23.8**	**22.4**	**25.6**	**23.0**	13.5	15.2	15.0	15.3	14.8
Light sour crude oil	**70.8**	**73.8**	**54.8**	**73.9**	**68.3**	31.4	31.5	40.6	64.3	42.0
Bitumen	**0.3**	**8.9**	**15.4**	**12.2**	**9.3**	8.6	13.0	8.0	4.3	8.5
	188.1	**197.3**	**206.7**	**228.4**	**205.3**	106.5	114.7	117.8	146.3	121.5
Average sales price (dollars per barrel)										
Light sweet crude oil	**33.55**	**37.07**	**39.80**	**39.02**	**37.56**	36.09	36.05	35.20	30.22	34.17
Other (diesel, light sour crude oil and bitumen)	**25.53**	**30.33**	**30.86**	**31.04**	**29.58**	25.66	27.12	28.21	20.12	24.86
Total	**29.66**	**33.43**	**35.79**	**35.12**	**33.65**	30.84	31.40	31.43	24.43	29.17
Total[(a)]	**30.62**	**36.68**	**40.40**	**39.11**	**36.94**	38.17	38.35	37.37	25.65	34.21
(dollars per barrel sold rounded to the nearest $0.05)										
Cash operating costs[(1)]	**16.35**	**12.60**	**12.05**	**12.50**	**13.25**	15.40	17.00	18.25	17.45	17.00
Total operating costs[(2)]	**19.05**	**16.65**	**16.55**	**16.55**	**17.15**	18.60	19.65	20.95	19.40	19.60

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2002	**June 30 2002**	**Sept 30 2002**	**Dec 31 2002**	**2002**	Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001	2001
NATURAL GAS										
Gross production[b]										
Natural gas (millions of cubic feet per day)	**175**	**179**	**181**	**182**	**179**	177	177	176	180	177
Natural gas liquids (thousands of barrels per day)	**2.5**	**2.5**	**2.3**	**2.4**	**2.4**	2.3	2.3	2.4	2.4	2.4
Crude oil (thousands of barrels per day)	**1.4**	**1.7**	**1.3**	**1.5**	**1.5**	1.7	1.5	1.5	1.3	1.5
Total (barrel of oil equivalent per day at 6:1 for natural gas)	**33.0**	**34.0**	**33.8**	**34.2**	**33.7**	33.5	33.3	33.2	33.7	33.4
Average sales price										
Natural gas (dollars per thousand cubic feet)	**3.21**	**3.92**	**3.56**	**4.91**	**3.91**	10.73	6.78	3.90	3.10	6.09
Natural gas[a] (dollars per thousand cubic feet)	**3.21**	**3.92**	**3.56**	**4.91**	**3.91**	10.81	6.82	3.90	3.09	6.12
Natural gas liquids (dollars per barrel)	**22.53**	**28.25**	**31.66**	**35.14**	**29.35**	45.07	39.62	30.26	23.47	34.38
Crude oil – conventional (dollars per barrel)	**29.15**	**30.99**	**33.57**	**33.20**	**31.72**	37.35	36.75	33.17	27.17	33.92
Crude oil – conventional[a] (dollars per barrel)	**30.50**	**34.82**	**40.30**	**39.37**	**36.24**	42.12	42.30	37.86	28.60	38.14
ENERGY MARKETING AND REFINING										
Refined product sales (thousands of cubic metres per day)	**13.5**	**14.9**	**14.1**	**15.8**	**14.5**	14.9	15.3	15.1	14.0	14.8
Natural gas sales[c] (millions of cubic feet per day)	**82**	**—**	**—**	**—**	**—**	92	102	95	92	95
Margins										
Refining[3] (cents per litre)	**4.1**	**3.8**	**4.4**	**6.6**	**4.8**	6.2	8.1	4.3	3.7	5.7
Retail[4] (cents per litre)	**6.1**	**6.8**	**6.9**	**6.5**	**6.6**	6.1	7.6	5.9	6.9	6.6
Utilization of refining capacity (%)	**102**	**70**	**100**	**108**	**95**	88	98	99	83	92

(a) Excludes the impact of hedging activities.

(b) Currently all Natural Gas production is located in the Western Canada Sedimentary Basin.

(c) During the second quarter of 2002, the company sold its retail natural gas marketing business.

Definitions

(1) Cash operating costs – operating, selling and general expenses, taxes other than income taxes, and overburden cash expenditures for the period.

(2) Total operating costs – cash and non-cash operating costs (total Oil Sands expenses less purchases of crude oil and products, royalties exploration expenses, and (gain) loss on disposal of assets in Schedules of Segmented Data on pages 48 and 49).

(3) Refining margin – average wholesale unit price from all products less average unit cost of crude oil.

(4) Retail margin – average street price of Sunoco-branded retail gasoline net of federal excise tax and other adjustments, less refining gasoline price.

Metric conversion

Crude oil, refined products, etc. – 1m^3 (cubic metre) = approx. 6.29 barrels
Natural gas – 1m^3 (cubic metre) = approx. 35.49 cubic feet

FIVE-YEAR FINANCIAL SUMMARY

(unaudited)

($ millions except for ratios)	**2002**	2001	2000	1999	1998
Revenues					
Oil Sands	**2 659**	1 385	1 336	889	768
Natural Gas	**315**	458	428	306	290
Energy Marketing and Refining	**2 361**	2 588	2 604	1 779	1 533
Corporate and eliminations	**(431)**	(232)	(980)	(587)	(521)
	4 904	4 199	3 388	2 387	2 070
Net earnings (loss)					
Oil Sands	**793**	283	315	167	145
Natural Gas	**35**	117	98	41	24
Energy Marketing and Refining	**61**	80	81	27	37
Corporate and eliminations	**(128)**	(92)	(117)	(49)	(28)
	761	388	377	186	178
Cash flow provided from (used in) operations					
Oil Sands	**1 480**	486	655	405	320
Natural Gas	**164**	280	238	172	167
Energy Marketing and Refining	**107**	165	174	103	112
Corporate and eliminations	**(311)**	(100)	(109)	(89)	(19)
	1 440	831	958	591	580
Capital and exploration expenditures					
Oil Sands	**617**	1 479	1 808	1 057	507
Natural Gas	**163**	132	127	200	242
Energy Marketing and Refining	**60**	54	45	42	60
Corporate	**37**	13	18	51	127
	877	1 678	1 998	1 350	936
Total assets	**8 683**	8 094	6 833	5 176	4 104
Capital employed[a]					
Short-term and long-term debt	**2 686**	3 144	2 257	1 339	1 315
Shareholders' equity	**3 458**	2 780	2 472	2 108	1 499
	6 144	5 924	4 729	3 447	2 814
Less capitalized costs related to major projects in progress	**(510)**	(3 691)	(2 497)	(1 084)	(373)
	5 634	2 233	2 232	2 363	2 441
Total Suncor employees (number at year-end)	**3 422**	3 307	3 043	2 796	2 659
Ratios					
Per common share (dollars)					
Net earnings attributable to common shareholders	**1.64**	0.79	0.78	0.39	0.41
Cash dividends	**0.17**	0.17	0.17	0.17	0.17
Cash flow provided from operations	**3.22**	1.87	2.16	1.34	1.32
Cash flow provided from operations attributable to common shareholders	**3.11**	1.76	2.06	1.26	1.32
Return on capital employed (%)[b]	**14.6**	17.8	16.6	8.3	9.5
Return on capital employed (%)[c]	**13.8**	7.5	9.3	6.4	7.6
Return on shareholders' equity (%)[d]	**24.4**	14.8	16.5	10.3	12.3
Debt to debt plus shareholders' equity (%)	**43.7**	53.1	47.7	38.9	46.7
Net debt to cash flow provided from operations (times)	**1.9**	3.8	2.3	2.3	2.2
Interest coverage – cash flow basis[e] (times)	**10.6**	5.9	9.0	9.1	8.7
Interest coverage – net earnings basis[f] (times)	**8.2**	3.7	5.6	5.1	4.8

(a) Capital employed – see page 48.

(b) Return on capital employed – net earnings adjusted for after-tax interest expense divided by average capital employed. Average capital employed is the aggregate of capital employed at the beginning and end of the year divided by two.

(c) If return on capital employed were to include capitalized costs related to major projects in progress, it would be as stated on this line.

(d) Return on shareholders' equity – earnings as a percentage of average shareholders' equity. Average shareholders' equity is the aggregate of total shareholders' equity at the beginning and end of the year divided by two.

(e) Interest coverage – cash flow basis – cash flow provided from operations before interest expense and current income tax provision, divided by interest expense plus interest capitalized.

(f) Interest coverage – net earnings basis – net earnings before interest expense and income tax payments, divided by interest expense plus interest capitalized.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

(unaudited)

	2002	2001	2000	1999	1998
OIL SANDS					
Production (thousands of barrels per day)	**205.8**	123.2	113.9	105.6	93.6
Sales (thousands of barrels per day)					
Light sweet crude oil	**104.7**	56.2	64.3	52.7	58.8
Diesel	**23.0**	14.8	9.3	8.2	9.7
Light sour crude oil	**68.3**	42.0	35.8	37.5	26.6
Bitumen	**9.3**	8.5	6.2	3.8	—
	205.3	121.5	115.6	102.2	95.1
Average sales price (dollars per barrel)					
Light sweet crude oil	**37.56**	34.17	35.31	26.06	22.80
Other (diesel, light sour crude oil and bitumen)	**29.58**	24.86	27.09	21.48	21.16
Total	**33.65**	29.17	31.67	23.84	22.18
Total(a)	**36.94**	34.21	41.29	25.89	20.37
Cash operating costs (dollars per barrel rounded to the nearest $0.05)(b)	**13.25**	17.00	13.55	11.70	11.75
Total operating costs (dollars per barrel rounded to the nearest $0.05)(b)	**17.15**	19.60	17.25	15.05	14.00
Other oil sands statistics					
Overburden removed (millions of cubic metres)	**57.1**	50.9	30.7	22.5	22.2
Oil sands mined (millions of tonnes)	**147.3**	97.9	84.9	72.9	62.4
Average bitumen content of oil sands mined (per cent by weight)	**11.3**	10.4	11.1	11.6	11.6
Average crude yield of oil sands mined (barrels per tonne)	**.510**	.459	.491	.529	.547
Return on capital employed (%)(c)	**16.8**	20.1	22.8	12.9	16.3
Return on capital employed (%)(d)	**15.6**	6.4	10.6	9.2	11.6

(a) Excludes the impact of hedging activities.

(b) See definitions on page 75.

(c) See definitions on page 76.

(d) If capital employed were to include capitalized costs related to major projects in progress, it would be as stated on this line.

SYNTHETIC CRUDE OIL GROSS RESERVES

	Mining Reserves Synthetic Crude Oil			Firebag In-situ Synthetic Crude Oil			Total
(millions of barrels)	Proved	Probable	Total	Proved	Probable	Total	Proved and Probable
December 31, 1998	302	464	766	—	—	—	766
December 31, 1999	476	2 028	2 504	—	—	—	2 504
Revisions	(13)	6	(7)	—	—	—	(7)
Production	(41)	—	(41)	—	—	—	(41)
December 31, 2000	422	2 034	2 456	—	—	—	2 456
Additions	—	—	—	—	1 664	1 664	1 664
Revisions	(1)	(5)	(6)	—	—	—	(6)
Production	(45)	—	(45)	—	—	—	(45)
December 31, 2001	376	2 029	2 405	—	1 664	1 664	4 069
Additions	3	45	48	144	32	176	224
Revisions	54	(511)	(457)	—	—	—	(457)
Production	(75)	—	(75)	—	—	—	(75)
December 31, 2002	**358**	**1 563**	**1 921**	**144**	**1 696**	**1 840**	**3 761**

In their audits or evaluations of Suncor's mining and in-situ leases, Gilbert Laustsen Jung Associates Ltd. (GLJ) state that they believe there is at least a 90% probability and 50% probability that proved and probable reserves estimates, respectively, will be exceeded. Accordingly, Suncor's probable oil sands reserves have not been further reduced for risk associated with obtaining production from such reserves. GLJ's mining and in-situ reserves estimates consider recovery from leases for which regulatory approvals have been granted, and are stated before the deduction of Crown and other royalties. Suncor reports its proved and probable reserves in accordance with Canadian disclosure requirements. The terms "proved" and "probable" reserves have the meanings ascribed to them in National Policy 2B of the Canadian Securities Administrators. U.S. companies are prohibited from disclosing estimates of probable reserves for non-mining properties in filings with the United States Securities and Exchange Commission. As a result, reserve estimates may not be comparable to those made by U.S. companies.

For Firebag reserves, the additions in 2001 and the year-end 2001 closing balance have been adjusted from a bitumen value of 2,029 million barrels based on assumed coker (synthetic crude) yields of between 80% and 82%.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (continued)

(unaudited)

	2002	2001	2000	1999	1998
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**179**	177	200	226	247
Net	**124**	124	142	170	195
Natural gas liquids (thousands of barrels per day)					
Gross	**2.4**	2.4	3.0	4.2	4.9
Net	**1.7**	1.7	2.1	3.0	3.7
Crude oil (thousands of barrels per day)					
Gross	**1.5**	1.5	4.2	9.2	11.4
Net	**1.2**	1.1	3.3	7.5	9.4
Total (thousands of boe[(a)] per day)					
Gross	**33.7**	33.4	40.5	51.1	57.5
Net	**23.6**	23.5	29.1	38.8	45.6
Average sales price					
Natural gas (dollars per thousand cubic feet)	**3.91**	6.09	4.72	2.44	1.95
Natural gas (dollars per thousand cubic feet)[(b)]	**3.91**	6.12	4.73	2.48	1.95
Natural gas liquids (dollars per barrel)	**29.35**	34.38	36.66	19.32	15.13
Crude oil					
Conventional (dollars per barrel)	**31.72**	33.92	29.50	20.94	20.14
Conventional (dollars per barrel)[(b)]	**36.24**	38.14	39.80	24.01	17.37
Return on capital employed (%)[(e)]	**9.2**	32.1	17.2	5.5	3.3
Undeveloped landholdings[(c)]					
Oil and gas (millions of acres)					
Western provinces					
Gross	**0.5**	0.6	1.4	1.5	1.7
Net	**0.4**	0.5	1.1	1.2	1.3
International					
Gross	**1.2**	1.7	1.3	—	—
Net	**0.7**	1.3	1.1	—	—
Net wells drilled[(d)]					
Exploratory					
Oil	**—**	—	—	1	2
Gas	**2**	4	1	5	10
Dry	**19**	16	15	13	18
Development					
Oil	**—**	—	2	2	15
Gas	**18**	16	14	4	16
Dry	**4**	2	3	1	8
	43	38	35	26	69

(a) Barrel of oil equivalent – converts natural gas to oil on the approximate energy equivalent basis that 6,000 cubic feet of natural gas equals one barrel of oil.

(b) Excludes the impact of hedging activities.

(c) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.

(d) Excludes interests in 17 net exploratory wells and three net development wells in progress at the end of 2002.

(e) See definitions on page 76.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (continued)
(unaudited)

NATURAL GAS (continued)

RESERVES	Gross Crude Oil and Natural Gas Liquids (millions of barrels)	Gross Natural Gas (billions of cubic feet)	Net Crude Oil and Natural Gas Liquids (millions of barrels)	Net Natural Gas (billions of cubic feet)
Proved				
December 31, 1998	69	1 197	56	915
December 31, 1999	51	1 013	41	764
Revisions of previous estimates	(3)	(52)	(6)	(81)
Purchases of minerals in place	—	9	—	7
Extensions and discoveries	1	39	1	28
Production	(3)	(73)	(2)	(52)
Sales of minerals in place	(30)	(139)	(23)	(99)
December 31, 2000	16	797	11	567
Revisions of previous estimates	(1)	(3)	—	4
Extensions and discoveries	—	27	—	20
Production	(1)	(65)	(1)	(45)
Sales of minerals in place	—	(1)	—	(1)
December 31, 2001	14	755	10	545
Revisions of previous estimates	—	(35)	—	(18)
Extensions and discoveries	1	53	1	39
Production	(1)	(65)	(1)	(48)
Sales of minerals in place	—	(2)	—	(2)
December 31, 2002	**14**	**706**	**10**	**516**
Proved developed				
December 31, 1998	53	730	43	557
December 31, 1999	38	627	30	471
December 31, 2000	13	573	10	414
December 31, 2001	11	573	8	416
December 31, 2002	**11**	**584**	**8**	**426**

Proved reserves are those reserves estimated as recoverable with a high degree of certainty under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

Proved producing reserves are on production, or reserves that could be recovered from existing wells or facilities, where the current non-producing status is the choice of Suncor.

Gross reserves represent the aggregate of Suncor's undivided percentage interest in reserves including the royalty interest of governments and others in such reserves and Suncor's royalty interest in reserves of others. Net reserves are gross reserves less that royalty interest share of others including governments. Royalties can vary depending upon selling prices, production volumes, and timing of initial production and changes in legislation. Net reserves have been calculated following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year-end and anticipated production rates. Such estimates by their very nature are inexact and subject to constant revision.

All reserves are located in Canada. There has been no major discovery or other favourable or adverse event which caused a significant change in estimated proved reserves since December 31, 2002. The company has no long-term supply agreements or contracts with governments or authorities in which it acts as producer, nor does it have any interest in oil and gas operations accounted for by the equity method.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (continued)

(unaudited)

	2002	2001	2000	1999	1998
ENERGY MARKETING AND REFINING					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail[a]	**4.5**	4.3	4.2	4.1	4.1
Other	**4.4**	4.4	4.0	3.7	3.5
Jet fuel	**0.4**	0.7	1.1	1.1	1.0
Diesel	**2.9**	3.1	3.1	2.7	2.5
	12.2	12.5	12.4	11.6	11.1
Petrochemicals	**0.6**	0.5	0.6	0.7	0.7
Heating oils	**0.4**	0.4	0.4	0.4	0.6
Heavy fuel oils	**0.6**	0.8	0.6	0.5	0.7
Other	**0.7**	0.6	0.6	0.6	0.7
	14.5	14.8	14.6	13.8	13.8
Margins (cents per litre)					
Refining	**4.8**	5.7	5.9	4.0	4.1
Retail	**6.6**	6.6	6.6	7.4	7.0
Crude oil supply and refining					
Processed at Sarnia refinery (thousands of cubic metres per day)	**10.6**	10.2	10.9	10.6	11.0
Utilization of refining capacity (%)	**95**	92	98	95	99
Return on capital employed (%)[b]	**12.5**	18.4	20.5	6.0	7.4
Retail outlets[c] (number at year-end)	**384**	400	402	415	423

(a) Excludes sales through joint venture interests.

(b) See definitions on page 76.

(c) Sunoco-branded service stations, other private brands managed by Energy Marketing and Refining and Energy Marketing and Refining's interest in service stations managed through joint ventures. Outlets are located mainly in Ontario.

SHARE TRADING INFORMATION

(unaudited)
(Stock trading symbol SU)

The following share trading information reflects a two-for-one split of the company's common shares during 2002.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2002	**June 30 2002**	**Sept 30 2002**	**Dec 31 2002**	Mar 31 2001	June 30 2001	Sept 30 2001	Dec 31 2001
Share ownership								
Average number outstanding, weighted monthly (thousands)[a]	**446 270**	**447 685**	**448 412**	**448 839**	444 231	444 926	445 262	445 819
Share price (dollars)[b]								
Toronto Stock Exchange								
High	**30.00**	**29.50**	**28.51**	**27.20**	22.20	22.13	24.10	26.85
Low	**23.31**	**24.66**	**22.30**	**22.56**	15.85	18.53	19.03	20.75
Close	**28.75**	**26.60**	**27.31**	**24.70**	20.28	19.30	22.00	26.20
New York Stock Exchange – US$								
High	**18.57**	**18.57**	**18.25**	**17.16**	14.30	15.00	15.13	16.80
Low	**14.68**	**16.10**	**13.95**	**14.20**	10.50	12.18	12.50	13.05
Close	**18.08**	**17.86**	**16.95**	**15.67**	12.95	12.85	13.95	16.45
Shares traded (thousands)								
Toronto Stock Exchange	**108 140**	**96 043**	**93 144**	**91 947**	90 320	100 230	77 028	100 412
New York Stock Exchange	**16 971**	**23 680**	**19 420**	**19 933**	7 078	12 758	13 338	13 886
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.18**	**0.52**	**0.38**	**0.56**	0.25	0.37	0.13	0.04
Cash dividends	**0.0425**	**0.0425**	**0.0425**	**0.0425**	0.0425	0.0425	0.0425	0.0425

(a) The company had approximately 2,288 holders of record of common shares as at January 31, 2003.

(b) The company's common shares are traded on the Toronto and New York Stock Exchanges.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

INVESTOR INFORMATION

Stock Trading Symbols and Exchange Listing

Common shares (SU) are listed on the Toronto and New York stock exchanges. Suncor's 9.05% preferred securities (SU.PR.A-T) are listed on the Toronto Stock Exchange. Suncor's 9.125% preferred securities (SU.PR.A-N) are listed on the New York Stock Exchange. Both issues of preferred securities are redeemable in whole or in part, any time on or after March 15, 2004.

Dividends

Suncor's Board of Directors reviews its dividend policy quarterly. In 2002, an aggregate dividend of $0.17 per share was paid on Suncor's common shares.

Dividend Reinvestment and Common Share Purchase Plan

Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through optional cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, call Computershare Trust Company of Canada at 1-888-267-6555 or visit the Investor Information section of our web site, www.suncor.com.

Stock Transfer Agent and Registrar

In Canada, Suncor's agent is Computershare Trust Company of Canada, with locations in Calgary, Edmonton, Toronto, Montreal and Vancouver. In the United States, Computershare Trust Company, Inc. is located in Denver, Colorado.

Independent Auditors

PricewaterhouseCoopers LLP

Annual Meeting

Suncor's annual and special meeting of shareholders will be held at 10:30 a.m. MST on April 24, 2003 at the Sun Life Conference Centre, second level, 112 – 4 Avenue SW, Calgary, Alberta. Presentations from the meeting will be web-cast live at www.suncor.com.

Corporate Office

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For further information, to subscribe electronically or to cancel duplicate mailings

In addition to annual and quarterly reports, Suncor publishes a biennial Report on Sustainability. All of Suncor's publications, as well as updates on company news as it happens, are available on our web site at www.suncor.com. To subscribe to Suncor news, go to the news room section of our web site. To order copies of Suncor's print materials call 1-800-558-9071.

Sometimes shareholders receive more than one copy of our Annual Report. If you receive but do not require more than one mailing call Computershare Trust Company of Canada at 1-888-267-6555.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, go to www.investordeliverycanada.com and follow the instructions for enrollment. You will need the 12-character control number enclosed with the Voting Instruction Form sent to shareholders. If you hold Suncor Energy Inc. shares in multiple accounts, you will receive meeting packages and a corresponding control number for each account. You must register for each account.

CORPORATE GOVERNANCE

Suncor's Board of Directors is responsible for the selection, monitoring and evaluation of executive management and providing guidance to align management of the company's businesses with long-term shareholder interests.

The Board's oversight role encompasses Suncor's strategic planning process, risk identification and management, communication with investors and other stakeholders, and establishing and maintaining high ethical standards in the conduct of our business. A comprehensive description of Suncor's governance practices is available in the company's Management Proxy Circular on Suncor's web site at www.suncor.com.

Independence

Suncor's Board of Directors, is comprised of eleven directors, nine of whom have been determined by the Board of Directors to be independent of management. The role of chairman is assumed by an independent director and is separate from the role of chief executive officer. Three of the Board's four committees – the Audit Committee, the Board Policy, Strategy Review and Governance Committee, and the Human Resources and Compensation Committee – are comprised entirely of independent directors.

Share Ownership

The Board has set guidelines for its own, as well as executive share ownership. Shares held by each Board member and guidelines for executive share ownership are reported annually in Suncor's Management Proxy Circular.

Disclosure

Suncor is committed to providing current and prospective investors with high quality disclosure. Suncor's Board plays a key role in the oversight of the company's financial matters, including capital structure management, financial results reporting, and oversight of risk management, monitoring and mitigation procedures. The independent Audit Committee of the Board reviews the company's core disclosure documents and approves interim financial statements and interim management's discussion and analysis. Suncor's core disclosure documents containing annual financial information are reviewed and approved by the full Board.

STANDARDS, PRACTICES AND SYSTEMS

Suncor's Board of Directors is committed to maintaining high standards of corporate governance and regularly reviews Suncor's standards in the context of changing practices, expectations and legal requirements. In 2002, Suncor's Board completed an extensive review of Suncor's corporate governance practices in light of new and proposed standards and guidelines of the Toronto Stock Exchange (TSX), New York Stock Exchange (NYSE), and United States Sarbanes-Oxley Act. As a result of that review, the Board implemented a number of enhancements to Suncor's system of corporate governance. They include:

- Enhancements to Suncor's Standards of Business Conduct, including a new policy articulating Suncor's expectations for the integrity of financial data and reporting.
- A new process to address complaints and concerns about ethical matters, including confidential anonymous submission by employees of concerns relating to questionable accounting or auditing matters.
- New financial literacy requirements for members of Suncor's Audit Committee and a new requirement that at least one member of committee meet the Board's criteria as an "audit committee financial expert".
- New independence criteria reflecting TSX and NYSE standards and guidelines, against which the Board annually determines the independence of each of its members.
- Greater transparency of Suncor's ethics, values and beliefs, including full disclosure of Suncor's Standards of Business Conduct on Suncor's web site.
- A new policy precluding the company from retaining its external auditor for prohibited consulting services, and requiring all permitted non-assurance work performed by its external auditor to be approved in advance by the Audit Committee.
- Formal Audit Committee annual reviews of the company's reserves estimates, including a review of the independence and performance of the company's external reserve engineers.

CORPORATE DIRECTORS

JR Shaw (2,3)
Calgary, Alberta
Executive Chair
Shaw Communications Inc.
Chairman of the Board
Suncor Energy Inc.
Director since 1998

Mel E. Benson (1,4)
Calgary, Alberta
President, Mel E. Benson
Management Services Inc.
Director since 2000

Brian A. Canfield (2,3)
Point Roberts, Washington
Chairman, TELUS Corporation
Chair, Human Resources and
Compensation Committee
Director since 1995

Bryan P. Davies (1,4)
Toronto, Ontario
Superintendent, Financial Services
Commission of Ontario
Director 1991 to 1996
and since 2000

Brian A. Felesky (1,4)
Calgary, Alberta
Partner, Felesky Flynn
Director since 2002

John T. Ferguson (1,2)
Edmonton, Alberta
Chairman, Princeton Development Ltd.
Chairman, TransAlta Corporation
Chair, Board Policy, Strategy Review
and Governance Committee
Director since 1995

Richard L. George
Calgary, Alberta
President and Chief Executive Officer
Suncor Energy Inc.
Director since 1991

John R. Huff (2,3)
Houston, Texas
Chairman and Chief Executive Officer
Oceaneering International, Inc.
Director since 1998

Robert W. Korthals (1,2)
Toronto, Ontario
Chairman, Gerdau-Ameristeel Inc.
Chairman, Ontario Teachers'
Pension Plan
Chair, Audit Committee
Director since 1996

M. Ann McCaig (3,4)
Calgary, Alberta
President, VPI Investments Ltd.
Chair, Environment, Health and
Safety Committee
Director since 1995

Michael W. O'Brien (4)
Canmore, Alberta
Retired executive
Suncor Energy Inc.
Director since 2002

(1) Audit Committee
(2) Board Policy, Strategy Review and Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health and Safety Committee

In 2002, the Board of Directors met five times. Committees of the Board generally meet four or five times per year with the exception of the Audit Committee, which meets more frequently. In 2002, two directors each missed one Board and one committee meeting. All other members of the Board attended all scheduled meetings.

For further information about Suncor's corporate governance practices and the company's Standards of Business Conduct, visit www.suncor.com or call 1-800-558-9071 to order a copy of the company's Management Proxy Circular.

CORPORATE OFFICERS

Richard L. George
President and Chief Executive Officer

J. Kenneth Alley
Vice President, Finance

M. (Mike) Ashar
Executive Vice President, Oil Sands

David W. Byler
Executive Vice President, Natural Gas
and Renewable Energy

Terrence J. Hopwood
Senior Vice President
and General Counsel

Sue Lee
Senior Vice President, Human
Resources and Communications

Kevin D. Nabholz
Senior Vice President, Major Projects

Janice B. Odegaard
Vice President, Associate General
Counsel and Corporate Secretary

Thomas L. Ryley
Executive Vice President,
Energy Marketing and Refining

Steven W. Williams
Executive Vice President,
Corporate Development
and Chief Financial Officer

02 Member of Dow Jones STOXX Sustainability Indexes

The Dow Jones Sustainability Index (DJSI) follows a best-in-class approach comprising the sustainability leaders from each industry. Suncor has been part of the index since the DJSI was launched in 1999.

Imagine A Caring Company

As an Imagine Caring Company, Suncor contributes 1% of its pretax profit to registered charities. In 2002, Suncor's contributions totalled $4.5 million.

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"SUNCOR WILL BUILD ON THE SUCCESS OF THE PAST AS WE CONTINUE EFFORTS TO BUILD SHAREHOLDER VALUE IN THE NEXT DECADE AND BEYOND. COUNT ON IT." **Rick George** President and Chief Executive Officer

SUNCOR ENERGY

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